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Optimization of local renewable hydrogen production for ferry operation and export on Åland

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Abstract of master's thesis

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Abstract

The Åland islands currently rely to 70% on electricity imports from Sweden and 20% on own wind power production. There are plans for building more wind power capacity both on- and offshore. The *Smart Energy Åland* project is about implementing the *FLEXe Demo* project, which is about creating a demonstration roadmap, where the electricity of the Åland Islands is produced 100% with renewable energy sources and can run independently without interconnections. To add value to the demonstration, new technologies for storage and possible market regulations were looked into.

Running on island-mode has, during the course of the project, been proven not to be financially favorable. Therefore, an interconnection with potential export of excess generated wind power and import will be necessary.

This study focuses on the long-term energy storage by looking into the potential of hydrogen (H_2) production out of the excess generated wind power and the different business cases it could create. The benchmark of local H2 usage as fuel for ferry traffic and potential export, is investigated to identify the viability of the alternatives.

Two main scenarios with different electricity and gaseous H_2 production are used as base for the analysis. In the production chain, the electrolyzer, compressor and storage are taken into consideration. Fuel cell and conventional diesel engine ferries are being compared. After five years it is financially more profitable to use fuel cells before diesel engines due to social costs caused by emissions. Without social costs, the investment costs of fuel cells would have to decrease by 60-70% to compete with diesel engines. Fueling and transportation are discussed shortly.

The high capital expenses of electrolyzers, compressors and storage make it difficult for larger than 50 MW electrolysis systems to become profitable. The value of H_2 plays a significant role in the profitability of producing gaseous H_2 locally. A continuously running electrolyzer becomes easily profitable with higher prices of H_2 even if electricity has to be imported in times of no local production. Therefore, it is crucial to find the client who would value the produced H_2 the most.

Keywords compression, electrolysis, energy storage, ferry, fuel cell, gaseous hydrogen, hydrogen, NPV

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Sammandrag

Åland förlitar sig för tillfället till 70% på elimport från Sverige och 20% på lokalt producerad vindenergi. Det finns aktuella planer för att bygga ny vindkapacitet både på land och till sjöss. *Smart Energy Åland* projektet går ut på att verkställa *FLEXe Demo* projektet, som handlade om att skapa en handlingsplan för hur Åland skulle operera totalt självständigt med 100% lokalt producerad förnybar energi. Dessutom utreddes nya energilagringstekniker och möjliga marknadsregleringar för att hämta tilläggsvärde till Demoprojektet.

Under projektets förlopp påvisades att det inte är ekonomiskt lönsamt att operera helt och hållet utan sammanlänkning till fastlandet. Därför är en elkabel till fastlandet, med möjlighet till export och import av elektricitet, nödvändig.

Denna studie fokuserar på långsiktig energilagring igenom att undersöka potentialen för lokal väteproduktion av överloppsvindenergi och dess olika affärsplaner. Tanken är att skapa en riktlinje för lokal användning av vätgas som bränsle för färjetrafik och potentiell export genom att identifiera dugligheten av de olika alternativen.

Två huvudscenarier med olika kapaciteter på el- och väteproduktion används som bas för analysen. I väteproduktionskedjan tas huvudkomponenterna, elektrolys, kompression och lagring i beaktan. Bränsleceller och konventionella diesel motorer jämförs och efter fem år är det ekonomiskt lönsammare med bränsleceller p.g.a. sociala kostnader från utsläpp hos diesel motorer. För att bränsleceller skulle kunna tävla mot diesel motorer, borde deras investeringskostnader minska med 60-70% då sociala kostnader inte beaktas. Dessutom diskuteras kort tankning och transport av väte.

Elektrolysernas, kompressorernas och vätelagringens höga kapitalutgifter försvårar 50 MW elektrolyssystemens möjligheter att bli lönsamma. Vätgasens marknadsvärde spelar en betydande roll i lönsamheten av lokal vätgasproduktion. En elektrolyser, som opererar kontinuerligt, blir lättare lönsam med högre priser på väte även om elektriciteten måste importeras under tider då inte lokalt producerad elektricitet finns tillgängligt. Därför är det kritiskt att hitta de kunder som värderar den producerade vätgasen allra mest.

Nyckelord bränslecell, elektrolys, energilagring, färja, kompression, NPV, väte, vätgas

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Tiivistelmä

Ahvenanmaa turvautuu 70% sähkön tuonnista Ruotsista ja 20% paikallisesti tuotetusta tuulienergiasta. Tällä hetkellä Ahvenanmaalla on suunnitelmia rakentaa paljon uutta tuulikapasiteettia sekä maalle että merelle. *Smart Energy Åland* projektin aikeena on toteuttaa *FLEXe Demo* projekti, jossa luotiin etenemissuunnitelma, miten Ahvenanmaan sähkö tuotettaisiin 100% uusiutuvilla energianlähteillä ja mahdollisesti ilman yhteyksiä mantereille. Uusia varastointitekniikoita ja mahdollisia markkinasäätelyitä tutkittiin lisäämään demonstroinnin arvoa.

Toimiminen täysin ilman sähköyhteyksiä mantereelle on projektin aikana todistettu epätaloudellikeksi vaihtoehdoksi. Kaapeliyhteys on tarpeen sekä mahdollista ylijäämäsähkön tuntia että vientiä varten.

Tämä työ keskittyy pitkäaikaiseen energianvarastointiin kehittämällä eri liiketoimintatapauksia potentiaaliseen paikalliseen vedyntuotantoon ylijäämätuulienergiasta. Eri vedyn tuotantomääriä tutkitaan paikallista vedynkäyttöä varten polttoaineena lauttaliikenteeseen ja mahdollista vientiä varten vertaillakseen vaihtoehtojen toteuttamiskelpoisuutta.

Analyysiä varten pohjana käytetään kaksi *FLEXe Demo* projektissa sovittua sähkn tuotantoskenaariota. Näihin skenaarioihin luotiin muutama eri tapausta eri kapasiteetteineen tuottaa kaasumaista vetyä. Tuotantoketjussa on huomioitu pääkomponentit, elektrolyyseri, kompressori ja varastointi. Polttokenno- ja tavanomaisia diesel lauttoja vertaillaan keskenään ja viiden vuoden kuluttua polttokennot ovat diesel moottoreita kannattavampia päästöistä aiheutuvien sosiaalisten kustannusten takia. Kun näitä kustannuksia ei huomioida, polttokennojen investointikustannusten pitäisi laskea 60-70% ollakseen kilpailukykyisiä diesel moottoreiden kanssa. Lisäksi tankkausta ja vedyn kuljetusta on käsitelty lyhyesti.

Elektrolyysereiden, kompressoreiden ja vedyn varastoinnin korkeat pääomamenot heikentävät yli 50 MW elektrolyysijärjestelmien kannattavuutta. Vedyn hinnalla on merkittävä rooli paikallisen vedyntuotannon tuotettavuudessa. Jatkuvasti operoivan elektrolyyserin saa kannattavaksi kun vedyn arvo kasvaa, myös vaikka sähkö täytyy tuoda aikoina jolloin ei ole paikallisesti tuotettua sähköä saatavilla. Tämän takia on erityisen tärkeää löytää asiakas, joka tarvitsisi vetyä eniten ja on valmis maksamaan siitä hyvän hinnan.

Avainsanat elektrolyysi, energian varastointi, kompressio, lautta, NPV, polttokenno, vety, vetykaasu

Preface

"Smart Energy Åland" is a follow-up on the FLEXe Åland Demo project, where the aim was to create a demonstration roadmap of the Åland Islands running autonomously on 100% own renewable energy sources (RES). The work was divided into eight clusters; Wind, E-Storage, Smart Grid, Demand Response, Transport, Solar PV and Heat. Pöyry Switzerland Ltd., which I am working for, is leading the Storage cluster. CLIC Innovations Oy, founded by the Finnish Founding Agency for Innovation, TEKES (Business Finland), worked until the beginning of 2019 in creating a clear demonstration roadmap, after which a new platform company, Flexens Oy Ab, will implement "Smart Energy Åland".

Analyzing different storage scenarios within the duration of the FLEXe Demo, it became clear that large physical storages solutions will become very expensive and unreasonable since there is still an existing cable interconnection to both Sweden and Finland. The European Union (EU) has set an "electricity interconnection target", where all member states of the union are called to achieve interconnection of at least 10% of their installed production capacity by 2020 (European Commission, 2015). Instead of considering the Åland Islands to run on "island-mode", other opportunities to use the existing interconnections for exporting or importing electricity or producing hydrogen are taken into consideration. For this thesis, the alternative of including gaseous hydrogen in the energy system, will be studied in form of fuel for ferries and for potential export.

This thesis contributes to the project "Smart Energy Åland", where Flexens Oy Ab is interested in feeding the results from my work into their project, looking deeper into the opportunities and business cases of hydrogen usage in transferring and storing energy. I could secure industry interest in the proposed thesis done at the Aalto University, with great support by Professor Annukka Santasalo-Aarnio. Pöyry Switzerland's PM and Director of Renewable and Thermal Energies, Dr. Michael Grünenfelder, has committed himself to support this thesis. Their advice was irreplaceable.

Additional support and information was provided by the companies ABB, Allwinds, Ballard, Calvera, Foreship, Hexagon, Hofer Hochdrucktechnik, Hydrogenics, Innogy, ITM Power, Kraftnät Åland, McPhy, nproxx, Power Cell Sweden, Resato, Teraloop, Umoe Advanced Composites, Ventos Compressors, Woikoski and ÅF-Pöyry Finland. This feasibility study was financed by Flexens Oy Ab and Pöyry Switzerland Ltd.

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Espoo 15.8.2019

Amanda Grannas

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Abbreviations

AEC	Alkaline Electrolysis
CAPEX	Capital Expenses
CAES	Compressed Air Energy Storage
CHP	Combined Heat and Power
CO	carbon monoxide
CO_2	carbon dioxide
DSO	Distribution System Operator
EIGA	European Industrial Gases Association
EU	European Union
FCHJU	Fuel Cells and Hydrogen Joint Undertaking
FCV	Fuel Cell Vehicles
GWh	Gigawatt hours
H_2	Hydrogen
HFO	Heavy Fuel Oil
IGC	International Gas Carrier
IMDG	International Maritime Dangerous Goods
IPP	Independent Power Producer
kWh	kilowatt hours
LCOE	Levelized Cost of Electricity
LNG	Liquefied Natural Gas
LOHC	Liquefied Organic Hydrogen Carriers
MF	Motor Ferry
MGO	Marine Gas Oil
MW	Megawatt
MWh	Megawatt hours
NG	Natural Gas
NOK	Norway Krone
NPV	Net Present Value
O_2	Oxygen
O&M	Operation and Management
OPEX	Operational Expenses
P2G	Power-to-gas
PEM	Proton Exchange Membrane
PEMEC	Proton Exchange Membrane Electrolysis
PEMFC	Proton Exchange Membrane Fuel Cell
PHS	Pumped Hydro Storage
PPA	Power Purchase Agreement
PV	Photovoltaic
RES	Renewable Energy Sources
SOFC	Solid Oxide Fuel Cell
SOEC	Solid Oxide Electrolysis
TSO	Transmission System Operator
VRE	Variable Renewable Energy
VRES	Variable Renewable Energy Sources
WEC	World Energy Council

1 Introduction

The renewable energy target of the European Union (EU) is 20% out of the overall energy mix by 2020 (EUR-Lex. 2010). In many countries around Europe, Variable Renewable Energy Sources (VRES) play a significant role in the future energy mix. However, the fluctuating nature of wind and solar power lead to needs for grid stabilization and flexibility. The role of energy storage and reserve capacity becomes significant for safety of supply.

The *Smart Energy Åland* project is a continuation of the FLEXe Demo project, which was about creating a demonstration roadmap, where the electricity of the Åland Islands is produced 100% with renewable energy sources and can run independently without interconnections. The Åland Islands have been chosen due to their size, population density, and autonomy to change some regulation within the framework of the Finnish state. Åland, located in the Baltic Sea between Finland and Sweden, is an autonomous province of Finland with 29’489 (2017) inhabitants, of which ~40% live in the city Mariehamn (Åkerberg, I at al. 2018).

Currently Åland relies to 70% of its electricity on imports by undersea cables from Sweden, 80 MW AC. Another 20% is wind power produced locally and the residual 10% are covered by import from Finland, 100 MW DC, fossils and biomass. Most of the existing wind capacity is built on rocks in the archipelago in nearly offshore weather conditions, “offshore on the rocks”. During peak consumption periods the 20 MW and 10 MW gas turbines for back-up power, owned by Kraftnät Åland (KNÅ), need to be run. There are two electricity suppliers on Åland, Ålands Elandelslag and Mariehamns Elnät Ab. (Åkerberg, I. et al. 2018)

Flexens Oy Ab, a new platform company founded in the end of 2018, will implement *Smart Energy Åland*. CLIC Innovation Oy, founded by the Finnish Founding Agency for Innovation, worked on the FLEXe Demo project until the beginning of 2019 by creating a clear demonstration roadmap. The work was divided into eight clusters; Wind, Solar PV, E-Storage, Smart Grid, Demand Response, Transport and Heat. Pöyry Switzerland Ltd., which I am working for, led the Storage cluster.

The project focuses on Åland’s total electricity consumption, which currently is 300 GWh and is estimated to grow to ~400 GWh by 2030 with a peak capacity demand of 85 MW (Mörn, J. 2018). Additional power generation from wind is expected to be a significant addition to the generating capabilities, since the area has excellent wind conditions. There are several plans for constructing more wind power capacity. Solar PV has also been investigated as part of the electricity generation system and would be included with a small share to add versatility and demonstration value to the project even if solar power isn’t the most optimal source of energy for the Åland Islands.

Introducing a large share of variable renewable energy requires very large storage capacities, which are very high when the aim is to be totally autonomous. Therefore, introducing some non-variable renewable energy, such as Biomass, as base load would reduce the storage needs significantly. There will be two energy generation scenarios, based on discussions from different stakeholders of the FLEXe project, presented in Table 1 below. Scenario 1 is more likely to happen by 2030 whereas Scenario 2 takes into consideration all potential VRE that can be generated on Åland, regardless of the demand or consumption. Based on these two electricity production scenarios, electrolyzer capacities for producing gaseous H_2 are adapted to the hourly peaks and the demand of a potential fuel cell ferry.

Table 1: New capacities to be installed for energy generation in two scenarios, one including biomass and second only with VRES.

New capacity [MW]	Scenario 1	Scenario 2
Wind[1]	85	170
PV	15	20
Biomass	20	-

The aim of the FLEXe project was to demonstrate how to make the Åland Islands run autonomously with electricity production consisting of 100% renewables. Running on island-mode has, during the course of the project, been proven not to be financially favorable. Therefore, an interconnection with potential export of excess generated wind power or locally produced gaseous H_2 will be necessary. To add value to the demonstration, new technologies for storage and possible market regulations were looked into.

This thesis focuses on the long-term energy storage by looking into the potential of H_2 production out of the excess generated wind power and the different business cases it could create. The benchmark of local H_2 usage as fuel for ferry traffic and potential export will be investigated to identify the viability of the alternatives. Main research questions:

- What is the optimum H_2 production for a viable business case exporting electricity vs. gaseous H_2 to SWE/FIN?
- What is the technically and commercially viable potential for local wind-biased H_2 production?
- What is the potential to monetize such H_2 production (from local consumption to powering ferries and exporting H_2 as fuel)?

Based on the two energy generation mixes with 100 % own renewable energy production over the year, there are three main alternatives; benchmark local H_2 use for ferry traffic, export of H_2 and export of electricity.

1. H_2 as fuel for e.g. ferries
2. Export of H_2
3. Export of electricity

For the time being, in case of excess wind power production, electricity is exported mainly to Sweden. The alternatives for using H_2 are to be investigated. These above described scenarios, visualized in Figure 1, lead to very different infrastructural, storage and transport requirements with varying capital and operational expenses, which are analyzed later on in section 4.

[1] ~21 MW of wind capacity is already installed on Åland (Saari P. et al. 2019)

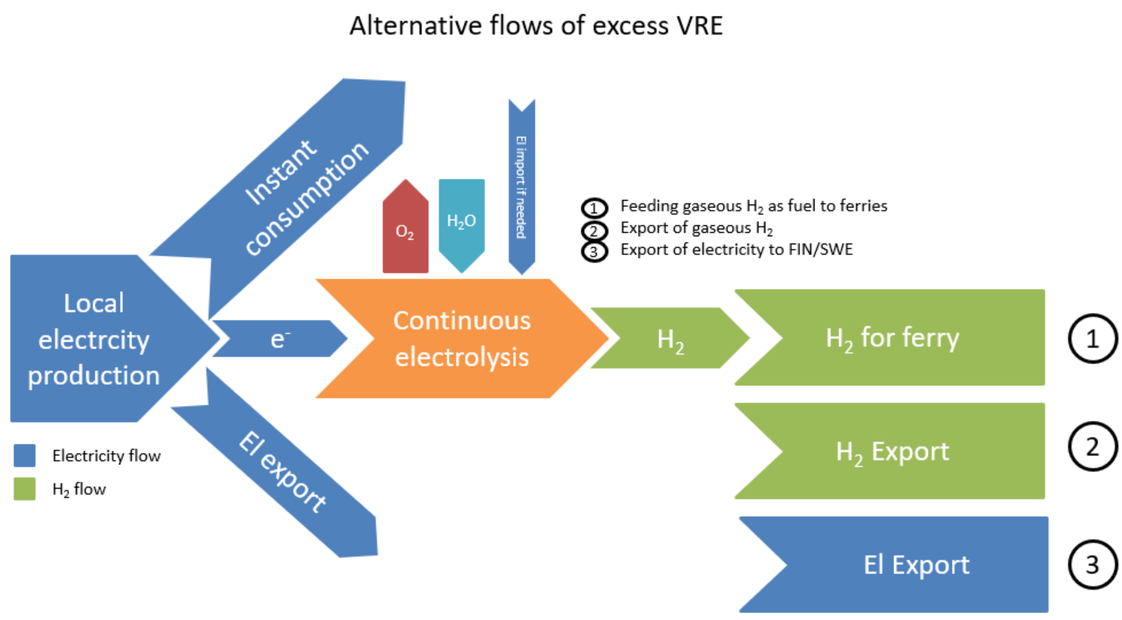

Figure 1: Graphic presentation of the main scenarios for the use of produced excess renewable power.

The FLEXe project is hailing a significant reconstruction of Åland's energy set-up. The envisaged introduction of renewables combined with storage assets and H_2 production will require new policies on market regulations for industrial and domestic energy pricing and for tax regimes.

There could be a significant business potential for the Åland Islands to export wind power. Without exporting wind power, Åland would either see significant amounts of electricity stored locally at high cost, transformed into H_2, or the Independent Power Producer (IPP) would have to curtail the production, which would in turn destroy the business case. This discussion has not yet been held at the political level.

As the project will design bankable investment packages, further study and simulation of network stability for Sweden and Finland would be needed. For a broader understanding and increased benefit for Åland, the impact of heat should be included in the study when scenarios are clearer defined.

"*The moment has come to develop and deploy renewable hydrogen at industrial scale. … we think that in order to fully unlock the potential of renewable energy we need to store large quantities of it*." – Michele Azalbert, Engie

1.1 Current plan for developing "Smart Energy Åland"

Smart Energy Åland project is about demonstrating a solution of a future flexible energy system based on 100% variable renewable energy production and envisioned to rely heavily on wind energy, 70-80% of the annual electricity generation, and the rest originating from solar power and/or biomass, 10-15% each. There are existing plans for 170 MW of new wind power capacity.

The targeted amount of solar power could be accommodated from roofs of existing buildings. On the other hand, a solar park would be more efficient in terms of CAPEX, OPEX and energy yield providing the lowest solar energy costs. CHP using biomass is seen as a cost-efficient option to provide both storage and flexibility to the energy system. (Saari, P. et al. 2019)

There are plans for implementing electric buses to the public transport system of Mariehamn and to convert some ferry routes, presented in Table 2 below, to be trafficked by electric, hybrid or fuel cell (fueled by gaseous H_2) ferries.

Table 2: Planned ferry routes to be electrified totally or partly. (Saari P. et al. 2019) (Nordlund E. 2019)

Ferry route	Project information	Fuel	one-way route time	Running by the year
Töftö – Prästö	Current ferry to be converted to an e-ferry	Electricity or gaseous H_2	4 min	2020
Main land Åland – Föglö	Hybrid e-ferry with battery capacity 1000 kWh + onboard diesel engines Ongoing tender	Electricity + diesel	20 min (10 min charging)	2022
Föglö – Kökar	Hybrid e-ferry	Electricity + diesel	50 min	2022
Föglö – Sottunga	e-ferry		35 min	

Changes are needed in the market model to enable better flexibility in the energy system, requiring a local market place for power and promoting demand response for load shifting.

For now, the storage technologies looked into during the FLEXe Demo are Li-ion batteries, flywheels and Power-to-gas (P2G), where H_2 would be used as energy carrier since there is lack of local industrial carbon dioxide sources on Åland to convert H_2 into methane (CH_4). Due to the high storage costs with a large share of VRES, relying on electricity transmission cables to mainland Finland and Sweden as a virtual storage would be a more profitable solution.

Two different scenarios, as presented in Table 1, are created based on the conclusions from the sub-groups of the FLEXe Demo project. The idea is possibly to sell excess electricity to the open markets, store it or produce another product, gaseous H_2 in this study, by using potential power-to-x processes. (Saari, P. et al. 2019)

1.2 Exclusions

- Ferry demonstrations, that don't run on pure H_2 (i.e. LNG excluded) or are adapted to longer distances than required for the Åland local transportation network.
- Option of feeding H_2 into a natural gas network since that doesn't exist on Åland.
- Methanation (converting H_2 into CH_4) due to lack of CO_2 (carbon dioxide) and CO (carbon monoxide) intensive industry on Åland.
- Liquefied-gas storage, since there won't be production of LNG. The process is highly energetic and would need to be on a larger scale than suited for Åland.

2 Methodology

There are existing reports on the optimal location of the demonstration, evaluation of different energy generation systems and identification of beneficiaries of this project for the Åland Islands. Reports and existing demonstrations within the H_2 field provide up to date information about H_2 technologies and its financials.

In addition, data from the local stakeholders, TSO's and DSO's, electrolyzer, compressor and fuel cell manufacturers, gaseous H_2 storage producers and information from experienced experts within energy generation, storage and transportation is needed to carry out the analysis.

Chapter three is built up according to the value chain and energy generation and exploitation circle. Choosing the most suitable technologies for the H_2-system on Åland was carried out through technology monitoring with the following criteria: maturity of the technology, current price, future price predictions, energy density, efficiency, scalability suitable for Åland and whether the technology is already proven in existing reference projects.

Chapter four discusses the results for using H_2 on Åland for ferries and export. The potential ferry operator and producer of H_2 were used as different business cases since they would most probably be run by different operators, where the H_2-producer would sell its gaseous H_2 to the ferry operator.

The feasibility of a H_2 ferry in comparison to a conventional ferry was looked into by both taking the environmental impact into consideration and not considering it. The NPV and costs distributed over different time periods were used for comparing the different ferry cases.

The two main energy production scenarios, agreed to during the FLEXe Demo project, were exploited further with different electrolyzer usages. The Biomass Baseload scenario has a smaller electrolyzer running continuously and the High-Wind scenario a larger electrolyzer adapted to different degrees of hourly excess power production and running only when excess power is available. The amount of potential H_2 production for local use and export, amount of electricity export and import and size of the electrolyzer, compressor and storage and their corresponding CAPEX and OPEX were fundamental parameters for analyzing the financial feasibility of the scenarios. Finally, the NPV value was used to compare the different H_2 generations cases. With different costs of gaseous H_2 the NPV value would change dramatically and make even exporting H_2 profitable.

3 P2G2P – The H_2 value chain

Power-to-X, or power-to-H_2 in this case, is currently regarded as an integral part of the transformation towards a low carbon energy system (WEC. 2018). Renewable H_2 has the potential to decarbonize the energy system by storing renewable power to when needed. The main reasons in favor of H_2 include:

- **Reduce CO_2-emissions:** Electrolysis and reverse electrolysis doesn't emit hazardous emissions during use. In a methanation process, CO_2 can be bound to synthetic fuels, i.e. methane. P2G encourages use of RES.
- **Lack of alternatives for fossil fuels**: Fuels for longer transportation distances, i.e. ships, buses or aviation, and a higher energy density are required in some

sectors. H_2 as such or synthetic fuels can be an alternative for fossil fuels. Going for more green synthetic fuels, reduces the political dependence on oil.

- **Facilitate higher VRE penetration**: There is lack of long-term storage alternatives. Higher VRE penetration requires long term energy storage. All regions don't have the suitable geography for pumped hydro storage (PHS), which is currently the most efficient method for long-term energy storage. PHS is also more suitable for stable power supply.
- **Similar to existing infrastructure:** The way to fuel H_2, and most synthetic fuels, to vehicles and vessels is similar to existing fueling intervals with conventional fuels. This advantage speeds up the global market for H_2.
- **Growing market:** Especially the petrochemical industry and transportation have an increasing demand for H_2. Regions with high production of wind or solar power can become exporters of synthetic fuels.
- **Versatile use of H_2**: H_2 can be used for storing energy, as fuel for transportation, fed into the gas grid (not on Åland) or for heat production when using SOFC (Solid Oxide Fuel Cells). Synthetic fuels can be stored in gas, liquid or solid form.

Hydrogen has a significantly higher heating value compared to synthetic fuels and their components as presented in Figure 2. The higher heating value 142 MJ/kg of H_2 equals to an energy content of 39,44[2] kWh/kg.

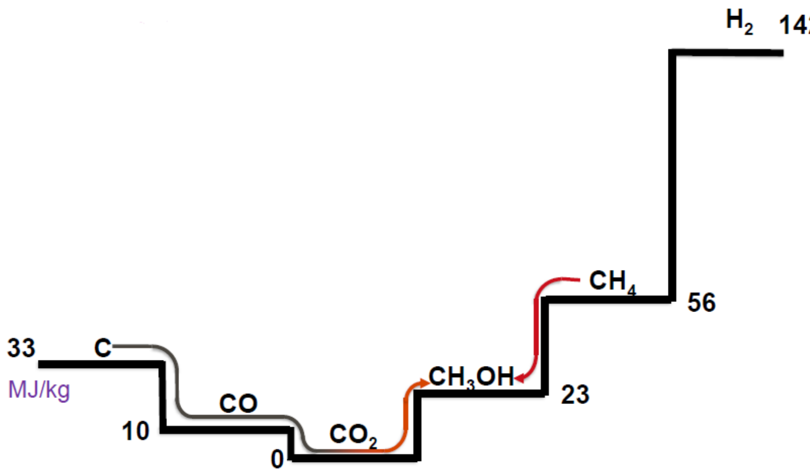

Figure 2: Higher Heating Values (HHV) of fuels compared to the one of H_2. (Lehtonen, A. 2019)

Table 3: Calorific energy densities of conventional fossil fuels for ferry traffic, MGO (Marine gas Oil), HFO (Heavy Fuel Oil), LNG (Liquefied Natural Gas) and H_2. (Engineering ToolBox. 2008)

	Mass energy density (LHV) [MJ/kg]	Volumetric energy density [MJ/l]
H_2 (gaseous)	141,7	0,0127 (1 bar) 25,8 (350 bar) 34,1 (500 bar) 41,4 (700 bar)[3]
MGO	45,9	39,2
HFO	41,8	41,0
LNG	55,2	23,6

[2] $MJ = 10^6(Ws) = 10^3(kWs) = \frac{10^3}{3600s}kWsh = \frac{5}{18}kWh \rightarrow 142\ MJ = 39{,}44\ kWh$

[3] More details to the densities in different pressures presented in section 3.2.1 and Table 7

H_2 has the highest mass energy density amongst other alternative and fossil fuels, but one of the lowest volumetric energy densities in 1 bar, as compared in Table 3. Increasing the pressure increases also the volumetric energy density. With pressures above 500 bar the volumetric energy density approaches the one of fossil fuels. Today, ferries use pressures of 350 bar.

3.1 Wind-to-H_2

P2G entails the conversion of surplus electricity from VRES, wind or solar power, via electrolysis into H_2 and/or methane CH_4, which can be re-electrified in fuel cells or combined cycle gas turbines and can therefore be used for network balancing and energy storage on a timescale of milliseconds up to weeks. However, when comparing the Levelized Cost of Energy (LCOE), P2G is better suited for mid- and long-term storage applications (Schulze, P. et al. 2017).

The power-to-power chain includes an electrolyzer, compressors, storage and fuel cells. In practice, wind turbines or PV panels can be linked to electrolyzer stacks, which use the generated electricity to split water into H_2 and O_2. The H_2 can then be stored, usually compressed, to be converted back to electricity during peak-demand hours (power-to-power) or used as it is for e.g. transportation (power-to-mobility). This type of H_2 produced from VRES is called Green Hydrogen.

There are several ongoing demonstrations in the field of wind-to-H_2 in Europe. Table 4 below summarizes a few of the largest and most recent ones.

Table 4: Ongoing or starting wind-to- H_2 in Europe.

Location	Companies	System
Falkenhagen, Germany	Owner: E.ON Technology: Hydrogenics Founding: Uniper	Wind-to-H_2, 360 Nm^3/h, via water-eletrolysis. The H_2 is fed into the area's natural gas grid. Since summer 2018, the project has been extended with a methanation plant. (Uniper. 2018)
Weiringerwerf, Netherlands	Owner: HYGRO, ECN Technology: Lagerwey	Wind turbine project with an incorporated electrolyzer to be started in 2019 with H_2 distribution to at least five H_2 fuel stations and 100 H_2 trucks. (Lagerwey. 2018)
Delfzijl, Netherlands	Owner: AkzoNobel, Gasunie	Largest proposed wind-to-H_2 facility of 20 MW project to be commenced in 2019. (AkzoNobel. 2018)
Raggovidda, Norway	Owner: Haeolus (SINTEF, Université de Bourgogne Franche-Comté, Tecnalia, uniSannio, Varanger Kraft, KES) Technology: Hydrogenics	Extension of Raggovidda wind park from 45 MW to 200 MW produces lots of excess energy to be converted into H_2, which can be stored for later, exported or used for mobility. (Hydrogenics. 2018)
Dassenweld, Belgium	Owner: Colruyt Founding: FCHJU	Don Quichote is a project for converting renewable energy, wind and solar power, into H_2 130 kg/day, to be re-electrified later or used as fuel for H_2 vehicles. (Don Quichote. 2019)

The system needs an electrolyzer suited for operation with variable power supply. In order to make the electrolyzer financially feasible, it is important to increase the annual operational hours of the electrolyzer. Adding non-VRE to the power system increases the number of operational hours. Sections 4.2.3 and 0 demonstrate these statements.

The CAPEX for onshore wind power is ~1100 €/kW and offshore ~2500 €/kW (Child M. 2016) resulting in an LCOE of 40 – 50 €/MWh (Fortum. 2017). Similarly, for PV power the CAPEX is 900 €/kW for ground-mounted and 1200 €/kW for rooftop installations (Child M. 2016) resulting in LCOE of 50 – 70 €/MWh (Fortum. 2017).

Production costs of H_2 vary between 5 and 13 €/kg, depending on the price development of alternative fossil fuels (oil and gas), investment costs of the electrolyzer and fuel cell and whether it is power-to-power or power-to-mobility (Loisel, R. at al. 2015). No single price for H_2 can be considered since it depends on the supply chain, with different conversion, compression and efficiency losses and CAPEX (Manenteau, P. 2011). Investments for the total system would include, except for the wind power plants, the electrolyzer, compressor, storage and potential fuel cells. The excess produced wind power can be at zero cost.

In an off-grid system the production of H_2 rises to 15-20 €/kg due to the higher requirements in H_2 storage and electrolyzer, compressor and fuel cell sizing for peak demand and power generation. However, in an off-grid system it is clearer from where the electricity in reality originates. The larger the system, the lower the production costs. For traffic, the operation costs with fuel cells should not be higher than with diesel. If fueling on a daily basis is possible, gaseous hydrogen is a feasible alternative (Vänskä, K. 2019). (Manenteau, P. 2011)

3.1.1 **Electrolysis**

The core component of the P2G concept is the electrolysis cell, where separation of water molecules to hydrogen and oxygen occurs by applying an electric current. 1 kg of H_2 requires 38 kg of water (Lambert, M. 2018) and on average 47 – 52 kWh of input electricity (Bertuccioli, L. et al. 2014). Due to a non-existing gas network on Åland and the aim to have a clean electricity production, this research only covers water electrolysis.

There are several technologies for electrolysis, Alkaline Electrolysis (AEC), Proton Exchange Membrane Electrolysis (PEMEC) and Solid Oxide Electrolysis (SOEC). SOEC is the most efficient one but operates at high temperatures and is not yet commercialized. AEC is the most established, cheapest and operates at low temperatures but needs 30-60 minutes to restart and cannot be moved due to their structure and internal parts. PEMEC is newly commercialized, has better start-up and moving characteristics than AEC but is more expensive and has a shorter lifetime. Since batteries and flywheels take care of the network stabilization, AEC is suitable for the requirements of mid- and long-term storage. (Lambert, M. 2018)

The overall electrolysis reaction is $H_2O \rightarrow H_2 + ½O_2$ for all here described three types of electrolysis. The charge carrier is different depending on the technology. Table 5Table 5 below summarizes the most central properties for choosing a suitable electrolyzer system.

Table 5: Main characteristics of the AEC, PEMEC and SOEC system. (Schmidt, O. et al. 2017) (Carmo, M. et al. 2013) (Steinmüller, H. et al. 2014.) (Saba, S.M. 2018) (Bertuccioli, L. 2014) (Thomann, O. 2017) (Ferrero, D. et al. 2016) (IEA. 2015) (Götz, M. 2015) (Hydrogenics. 2018) (Hamalainen, A. 2019)

	AEC	PEMEC	SOEC
Anode reaction	$2OH^- \rightarrow ½O_2 + H_2O + 2e^-$	$H_2O \rightarrow 2H^+ + ½O_2 + 2e^-$	$O^{2-} \rightarrow ½O_2 + 2e^-$
Cathode reaction	$H_2O + 2e^- \rightarrow ½H_2 + 2OH^-$	$2H^+ + 2e^- \rightarrow H_2$	$H_2O + 2e^- \rightarrow H_2 + O^{2-}$
Electrolyte	Aq. Potassium hydroxide	Polymer membrane	Yttria stabilized Zirconia
Cathode	Ni, Ni-Mo alloys	Pt, Pt-Pd	Ni/YSZ
Anode	Ni, Ni-Co alloys	RuO_2, IrO_2	YSZ
H_2 production [m^3/h, STP]	<760	<40	<40
Tap water consumption [l/Nm^3 H_2]	<1,7	<1,4	Lab scale
Electrolysis efficiency [%]	71	70	82
Operating temperature [°C]	60 – 80	50 – 80	650 – 1000
Operating pressure [bar]	<30	<200	<25
Electrolysis current density [A/cm^2]	0,2 – 0,5	0,5 – 1,5	0,4 – 2,0
System power consumption [kWh/ m^3 H_2]	4,7 – 5,4 5,4 – 8,2	5,2 – 7,1 4,9 – 5,2	>3,7
Response time	Seconds	Milliseconds	Seconds
Cold start time [min]	<60	<20	<60
Lifetime [h]	60’000 – 90’000	12’000 – 60’000	<10’000
Maturity	Mature	Commercial	Demonstration
Capital cost (2015) [€/kW]	760 – 1100	1200 – 1940 1500[4] (800 for systems over 50 MW)	>2000
Capital cost (2020) [€/kW]	370 – 900	700 – 1300	1300 – 3000
Capital cost (2030 prediction) [€/kW]	787 – 906	297 – 955	500 – 1000
O&M cost [€/kW/year]	64	48	Lab scale
Electricity input (2020) [kWh_{el}/kg_{H2}]	49 – 67	44 – 61	Lab scale
Electricity input (2030 prediction) [kWh_{el}/kg_{H2}]	48 – 63	44 – 53	Lab scale

[4] (N.N. Belgian electrolyzer supplier. 2019)

Electrolyzers, that operate with fluctuating power input, need fast responses of system components, reliable and clean operation even at lower dynamic range and quick cold-start or energy efficient stand-by. PEMEC fulfil best the requirements for operation with fluctuating power supply, but AEC and SOEC can also be adapted to different cases (Schmidt, O. et al. 2017). To start producing gas, not to its maximum operating point, PEMEC have response times of 30 seconds from 'standby' and 300 seconds from 'off' (Ellis, A. 2019). In case very rapid response times are important, it is possible to have the electrolyzer in a state, where all sub-systems are running, H_2 is not being generated but moving to generation can happen in less than 2 seconds (Ellis, A. 2019). The issue with fluctuating power supply lies in the rectifier and transformer, not the electrolyzer (Braatz, C. 2019). Even in periods of inactivity, permanent available power connection must be available to ensure adequate thermal control of the system (Olsen, K. 2019). Parallel coupling of electrolyzer stacks and steering of operation with varying capacities help to reduce efficiency losses from ramp-ups and stand-by states increasing the life-time of the stack. (Steinmüller, H. et al. 2014.)

In general, AEC is more efficient on large scale in comparison to PEMEC but due to the larger current density of PEMEC compared to AEC, the spatial footprint of the electrolyzer containers can be a lot smaller. Hydrogenics reports the current density of PEMEC to be six times larger than the one of AEC. The covered area can be 5-10 times larger in AEC electrolyzers compared to the PEMEC (Hydrogenics. 2019). Electrolyzers are dependent on fluctuating power input, wherefore fast responses for system components are crucial for dynamic H_2 production.

The AEC of Woikoski Oy in Finland produces H_2 at a price of ~0,5 €/Nm^3 = 5,56 €/kg[5] from either a natural gas or a by-product from Kemira chlorate production. (Hämäläinen, A. 2019).

3.2 H_2 storage

H_2 storage is one of the major technical constraints to encourage advancement of H_2 as a fuel. The losses of H_2 during storage are marginal but the conversion stages cause the most significant losses.

Due to the fact that H_2 has one of the lowest volumetric energy densities, but high mass energy density, methods for increasing the volumetric energy density are crucial for making H_2 competitive to fossil fuels, such as e.g. gasoline (see Table 3 for comparison of gasoline and H_2). One of the biggest challenges for H_2 transportation is storing a sufficient amount of H_2 on board to reach acceptable ranges. Increasing the volumetric energy density of H_2 can be done through compression, to low or high pressures (350-700 bar), or liquefaction by reducing the temperature to extremely low temperatures. Compressed and liquid H_2 (LH_2) are currently the most popular ways to store H_2. Alternatively, H_2 can be stored in solid state in metal hybrids. (Zhang, J. Z. 2015)

We exclude liquefied-gas and LNG storage since their production requires lots of energy and needs to be on a larger scale than Åland to become profitable (Goodwin, A. 2015). LOHC (Liquefied Organic Hydrogen Carriers) store H_2 in a mineral oil. This way of

[5] Normal conditions, $pV = nRT \rightarrow m = \frac{pVM}{RT}$, p= 101.325 kPa, T=273.15 K, R=8.314 J/molK
$m = 44{,}6175\ mol/m^3 * M * V \rightarrow m_{H2} = 44{,}6175 mol/m^3 * 2 * 0{,}001008\ kg/mol * 1 Nm^3 = 0{,}089949\ kg$
$\frac{0{,}5€}{Nm^3} = \frac{0{,}5€}{0{,}089949 kg} = 5{,}55871 \frac{€}{kg}$

storing H_2 requires electricity and releases lots of low quality heat during charging and can use 73 % of the stored H_2 when released (Marcoux, M. 2019).

When comparing the LCOE predictions for 2030 and 2050 of power-to-power applications, H_2-based storage, PHS and CAES (Compressed Air energy Storage), the H_2 based currently seem the most promising. The LCOE is around 200 – 400 €/MWh depending on the H_2 conversion technology and size of the storage. The corresponding LCOE is ~1000 and ~500 €/MWh for PHS and CAES respectively. This is mainly due to the higher energy density of H_2, which shifts the costs from storage to conversion technology, electrolysis. (IEA. 2015)

Storage systems for on-board a vessel have to be certified due to regulatory and safety issues according to existing *Guidelines for the Use of Fuel Cell Systems on Board of Ships and Boats*. The IMDG (International Maritime Dangerous Goods) code treats compressed gaseous H_2 as packed cargo. However, natural gas as fuel is treated according to the IGC (International Gas Carrier) code and may be used on-board passenger ships with higher passenger capacities than 25. Due to their similar properties, H_2 should be treated as strict as natural gas. Storing compressed gaseous H_2 (over 10 bar) above deck is favorable. (Tronstad, T. et al. 2017)

Regulation standards related to on-board H_2 storage include EN 12245 on storage tank materials (Hexagon. 2017), EN 1797-2001 on gas compatibility and EN 13648 on safety devices related to high pressure conditions. EIGA (European Industrial Gases Association) code IGC 15/06 includes the H_2 handling chain from compression to filling into containers. (Tronstad, T. et al. 2017; ISO/TC 197. 2018)

3.2.1 Compressed gaseous H_2

After electrolysis, compression to the desired pressure, depending on the H_2 application, is required. Some costs and efficiencies of a compressed storage system in Table 6 below, which shows the significant cost difference when moving towards higher pressures. Pressurized tank storages from different manufacturers are being looked into later in section 4.2.2.

Table 6: Components in a H_2 compression storage system. (IEA. 2015)

	Compressor 180 bar	Compressor 700 bar	Pressurized tank
Efficiency (LHV)	88 – 95%	80 – 91%	<100%
CAPEX	62 €/kW H_2	170 – 350 €/kW H_2	5’300 – 8’800 €/MWh (300 k€/400 kg H_2 tank[6])
Lifetime	20 years	20 years	20 years

The compressibility factor Z rises at higher pressures and lower temperatures, as indicated in Figure 3. A higher compressibility factor results in a higher volumetric density and using the ideal gas equation a higher mass than in reality. A compressibility factor of 1,4 indicates a 40% greater mass than in reality. At 700 bar and ambient temperature, the compressibility factor is ~1,5. The volumetric density increases from 0,0899 kg/m^3 to 41,4 kg/m^3 in 0˚C when increasing the pressure from 1 to 700 bar. (Carriveau R. & Ting D. S-K. 2016)

[6] Hämäläinen, A. 2019. Average CAPEX of Woikoski Oy pressurized tank

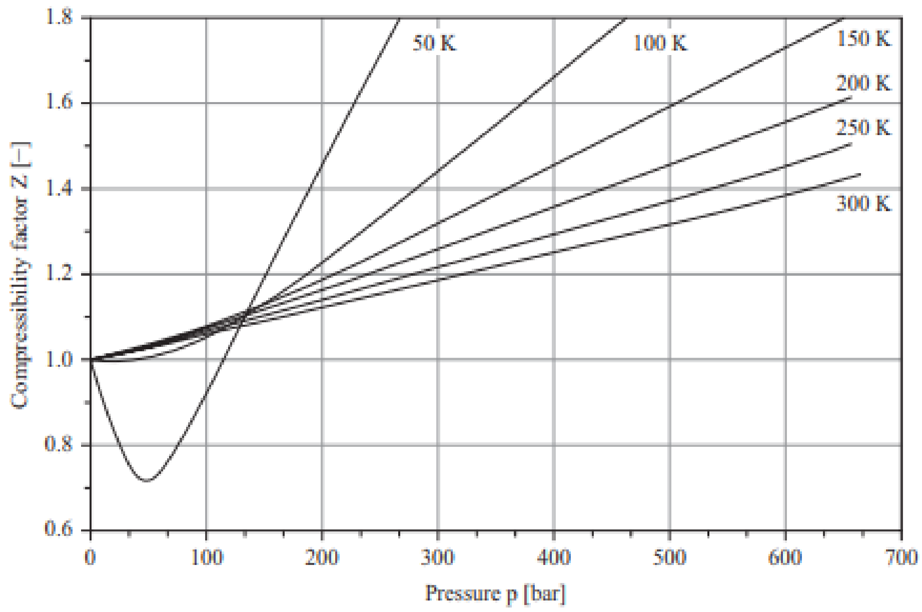

Figure 3: Compressibility factor Z of H_2. (Carriveau, R. & Ting, D. S-K. 2016)

The increase in the compressibility factor results in an increase in the volumetric density of H_2 gas, as visualized in Figure 4. Using the compressibility factor, Z, it is possible to calculate the exact volumetric density of gaseous H_2 in different pressures and temperatures. The most commonly used pressures in H_2 driven vessels and vehicles and their corresponding densities in zero degrees Celsius are compared in Table 7 below.

Table 7: Density of gaseous H_2 in different and the most commonly used pressures within transportation.

Pressure of the gaseous H_2 [bar]	Compressibility factor Z[7]	Density [kg/m^3][8]
1	1,0	0,0899
100	1,07	8,41
200	1,12	16,1
350	1,22	25,8
500	1,32	34,1
700	1,52	41,4

[7] Based on the graph in Figure 3

[8] $pV = ZnRT \rightarrow m = \frac{MpV}{RTR} = \frac{2*0{,}001008\frac{kg}{mol}*p\ Pa}{8{,}314\frac{J}{molK}*273{,}15K*Z}$

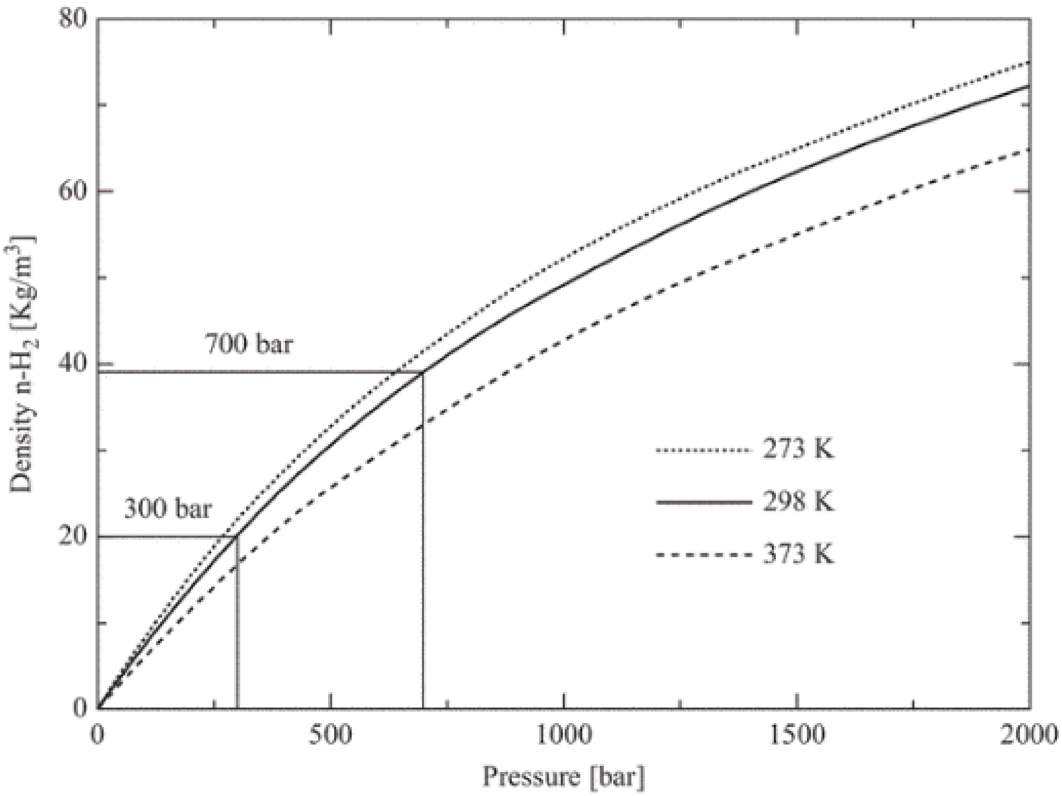

Figure 4: Evolution of the density of H_2 gas at increasing pressures and three different temperatures. (Carriveau, R. & Ting, D. S-K. 2016)

Compression of H_2 to low pressure is suitable for larger systems with longer storage times compared to the systems with high-pressure storage. Low-pressure gas storage systems consist of gas holders, two compressors, one for loading another for unloading hydrogen, and other equipment (Ozaki, M. et al. 2014).

Standard gas holders, made of heavy or aluminum-lined steel, operate at 100-200 bar, which is suitable for i.e. stationary underground H_2 storage. These tanks cannot hold enough H_2 for on-board applications. Woikoski in Finland uses gas storages of 200-300 bar, weighing roughly 400 kg (Hämäläinen, A. 2019). Today gas holders made of light composite fiber are preferred. (Zhang, J. Z. 2014)

For grid scale stationary storage it is important to keep the overall efficiency as high as possible. Due to the losses in compression, the pressure level of the storage should be as low as possible. A 200 bar H_2 storage requires about twice as much space as 500 bar one. If space is available, 200 bar is more profitable, whereas 300 or 500 bar should be considered in case of limited space. (Ismar, M. 2019)

Compression of H_2 to high pressure is suitable for shorter storage times due to lots of losses. High-pressure gas storage system consists of cylinder-cluster manifolds, booster compressor, a compressor for unloading hydrogen and other equipment (Ozaki, M. et al. 2014). The common storage cylinders today are composed of composite since it is much lighter than carbon steel and aluminum, which were the trend traditionally (Pratt, J.W. & Klebanoff, L.E. 2016).

New fuel cell vehicles today mainly store their on-board H_2 in high-pressure 700 bar, where the volumetric density is 35 g/l. Larger systems, where space is a smaller issue, often operate at 350 bar, which has a volume density of 20 g/l (SAE-China. 2018). In general, storage at 350 bar results in ~0,50€/kg lower H_2 costs than at 700 bars due to less compression and no refrigeration at the refueling station (Paster, M.D. et al. 2011). Especially for mobile applications, both the system weight and size plays a significant role. Compressors today are at the same size as a ship container.

The H_2 storage systems of several manufacturers have been looked into later in section 4.2.2 of this study.

3.2.2 Solid-State H_2

The requirements for higher volumetric and mass energy densities in fuel cells have been driven by light weight fuel cell applications, especially FCV (Fuel Cell Vehicles). Densities beyond the ones of high-pressure compressed H_2 systems, without increasing the system weight dramatically, are a challenge, for which solid state H_2 storage could be the solution. Two types of solid state H_2 storage are reasoned below. For the time being, neither of the following is yet close to being commercialized.

3.2.2.1 Metal hydrides

Metal hydrides are solid-state H_2 storage materials containing metal atoms. H_2 is soaked up through fast reactions when the material is imposed to H_2 gas and released fast when heated up. The spent material on-board a vehicle or vessel does not have to be removed. H_2 absorption happens at low pressures increasing safety, which is the reason that this solid-state H_2 storage is most favored by vehicle manufacturers. (Klebanoff, L.E. & Keller, J. O. 2013)

However, metal hydride materials are very heavy and swell up when absorbing H_2, leading to being nearly four times heavier than storing the corresponding amount of gaseous H_2 in 700 bar composite tanks (Pratt, J.W. & Klebanoff, L.E. 2016). The efficiency of metal hydrides and alternative more lightweight materials still require research.

3.2.2.2 Chemical hydrides

Chemical hydrides store H_2 in liquid form and can release the H_2 when heated. However, the original material can't be regenerated at a H_2 station since it requires chemical processing. Therefore the system needs off-board chemical processes, at e.g. a chemical plant, to reincorporate H_2 into the fuel, for example cyclohexane: $C_6H_{12} \rightarrow C_6H_6(benzene) + 3H_2$ (Pratt, J.W. & Klebanoff, L.E. 2016).

The advantages of chemical hydrides are that they can be handled like traditional gasoline. On the other hand, the resulting product after dehydrogenation, e.g. benzene, has to be stored on-board before unloading. If the resulting material would be solid, a system for swapping the tank would be necessary. Chemical hydrides still contain too much heat but not enough releasable H_2. Commercially, this storage type is not yet available and is not a suitable way of storing H_2 for ferries. (Pratt, J.W. & Klebanoff, L.E. 2016)

3.3 H_2-to-power

Seasonal or inter-seasonal storage allows load shifting and grid stabilization in the energy supply-demand balance over days, weeks or months. Stored H_2 can be re-electrified through a fuel cell, which produces electrical energy through oxidation and reduction of hydrogen and oxygen in the anode and cathode respectively. The reaction is the following:

$$Anode: 2H_2 \rightarrow 4H^+ + 4e^-$$
$$Cathode: O_2 + 4e^- + 4H^+ \rightarrow 2H_2O$$

The power-to-power chain requires an electrolyzer for producing the H_2 gas, a compressor and a storage system (**Error! Reference source not found.**), potential transportation infrastructure and a fuel cell (Table 8). The round trip efficiency of power-to-power, visualized in Figure 5, is ~30 % (electrolysis -70%, compression and transportation -10% and fuel cell -50%) (Hydrogenics. 2019. Phone interview).

Figure 5: Conversion efficiency, where storage losses are neglected, of H_2 based power. (IEA. 2015)

The main characteristics of the fuel cell systems, AFC (Alkaline Fuel Cell), PEMFC (Proton Exchange Membrane Fuel Cell) and SOFC (Solid Oxide Fuel Cell), are presented in Table 8.

Table 8: Properties of current hydrogen conversion, fuel cell, technologies. (IEA. 2015) (Convion. 2019) (Pratt, J.W. & Klebanoff, L.E. 2016.)

	AFC	PEMFC (stationary)	PEMFC (mobile)	SOFC
Electrolyte Mobile Ion	OH^-	H^+	H^+	O^{2-}
Power/Capacity [kW]	<250	0,5 – 400	80 – 100	<300
Efficiency (HHV)	~50%	32 – 49%	<60%	50 – 80%
Lifetime [hours]	5’000-8’000	~60’000	<5’000	<90’000
Fuel	H_2	H_2	H_2	NG or Biogas
Operating temperature (˚C)	50 – 200	50 – 100	50 – 100	500 – 1000
CAPEX [€/kW]	170 – 610	2650 – 3530	440	2650 – 3530

Fuel cells are modular and flexibly scalable. For re-feeding electricity to the grid, SOFC provides the most suitable properties with high efficiency, power capacity and lifetime. SOFC operates like a small CHP producing both heat and power in operation. Producing heat as a side product would bring a supplementary advantage for Åland. Heat recovery in SOFC systems and engine generators increase the fuel cell economy. However, SOFC are the most expensive fuel cells. PEMFC have also good efficiencies and power capacity and are significantly cheaper than SOFC, but don’t produce heat. Both PEMFC and SOFC have clear predictions of lowering CAPEX in the future. OPEX costs are estimated to be around 1-2% out of the CAPEX in all the above mentioned technologies. (Pratt, J.W. & Chan, S.H. 2017).

SOFC can be run on pure H_2 but reaches its highest degree of efficiency when running on natural gas (NG) or biogas, like synthetic CH_4. Therefore, SOFC would be suitable in case of integrated energy production with biogas. (Hakala, T. 2019)

PEMFC are the most promising for marine applications. It has low operating temperatures providing high cycling tolerances. On the other hand, low temperatures make heat recovery unfeasible. PEMFC require pure H_2 in use. (Tronstad, T. et al. 2017)

For the time being, large scale H_2 storage for balancing grid scale off-peak and peak electricity tariffs is not viable for an island positioned like Åland due to the conversion losses and high CAPEX.

3.4 H_2-to-mobility

Hydrogen as fuel in mobility has during the recent years been competing with lithium-ion batteries. Batteries have had an exponential market development with significant price decrease, hindering the development of hydrogen technologies. Battery Electric vehicles have an overall well to wheel efficiency of 77% (Losses in transport, storage and distribution -5%, charging -10%, inversion DC/AC -5% and engine -5%), whereas the corresponding efficiency is ~30% for H_2 vehicles (Losses in H_2O electrolysis -22%, transport, storage, distribution and H_2 compression -22%, H_2 Fuel Cell -46%, inversion -5% and engine -5%) (Transport & Environment. 2018). Relying only on batteries in the transportation sector will not be a sustainable solution (IEA. 2015). Losses in each stage of the supply chain are visualized in Figure 6 below.

Figure 6: The flow of excess produced energy to H_2 and conversion efficiency, where storage losses are neglected, of H_2 based fuel production from VRES. (IEA. 2015)

However, H_2 as fuel has an advantage to batteries concerning range, refueling time and weight. The current price of tanking H_2 for vehicles in Europe is 9-10 €/kgH_2. Filling the tank of a hydrogen driven and diesel driven vehicle, with the same drive reach, is in the same price range, ~50 € for H_2 and 60-70 € for diesel (Nikula, P. 2018).

In this study, the only H_2 fueled transportation method is considered to be ferries due to the fact that there is no existing H_2 fueling infrastructure. H_2 fueling can be centralized to e.g. ferry harbors. In the LNG fuel sector, the CO_2 emissions are 25% less compared to diesel. Especially for ships, this difference could reduce the greenhouse gases significantly (Handelsblatt. 2019). In the H_2 fuel sector the reduction in emissions is probably even larger. Several large diesel motor manufacturers are turning their business models towards H_2 technologies (Höpner, A. 2019). The technology and its seaworthiness is not the issue in fuel cell ferry projects, but certification and regulations for maritime use are big constraints (Tröger, M. 2019). For the time being, certification processes of H_2 gas projects for people transportation can be very time consuming and costly due to safety concerns. "*It's not the technology. It's the certification*" – Marcus Melcher, Hydrogenics

3.4.1 Distribution

For H_2-to-mobility, despite a H_2 production unit, compressors and storage banks, a H_2 refueling station and H_2 transport is necessary. In Finland there has been only three H_2 fueling stations, of which only one was public (TÜV SÜD. 2019). Currently there are no open public H_2 fueling stations.

Stored H_2 needs to be transported to the location, where it is needed.
Alternatives for H_2 distribution:

1. Cylinder trailer transportation on trucks
2. Gaseous pipeline distribution

(Paster M.D. et al. 2011)

The cylinder trailer delivery pathway may be used for high consumption and pressures, i.e. 350, 500 or 700 bars, directly suitable for ferries. The cylinders are then dropped off where needed. Especially for longer transportation distances, >50 km, high pressures are favorable. For shorter distances, like 10 km, lower pressures can be used to avoid compression losses (Ismar, M. 2019). In case the production plant is located close to the fueling point, no additional distribution system is needed.

Distribution of the gas through pipelines requires large H_2 production and consumption volumes and preferably an existing gas network. If these requirements are fulfilled, it could make sense to consider transportation of H_2 through pipelines.

In addition to compressors, fuel stations also typically consist of a cooling system, since H_2 heats up when flowing, as well as a steering system for the fueling (Hämläinen, A. 2019). Otherwise, fueling of hydrogen works similarly to fueling with conventional fuels when looking at the time it takes to fill the tank.

3.4.2 Conventional ferries

Today, most of the existing ferries are fueled by Marine Gas Oil (MGO) or Heavy Fuel Oil (HFO), which have heat values of 41-43 MJ/kg (MAOLs. 2011). Currently there are 41 conventional road ferries in Finland (ELY-keskus. 2017).

For the time being, the energy efficiency of conventional diesel engine ferries is 25-34% whereas the corresponding energy efficiency is 36-54% of fuel cell generators with the same load. In addition, conventional ferries have significant CO_2, NOx, CO, HC, PM and SOx emissions, which can almost be avoided using fuel cell generators instead. (Pratt, J.W. & Chan, S.H. 2017)

The main properties of the current most used ferry fuels and H_2 are presented earlier in Table 3 and a comparison of advantages and disadvantages of fuel cells and diesel engines for ferry traffic are collected in Table 9 below.

Table 9: Fuel cells vs. Diesel engines. (Pratt, J.W. & Chan, S.H. 2017) (Schulze, P. et al. 2017)

	Fuel Cells	Diesel Engines
Advantages	- Emission savings - Relatively constant fuel use at part load - Low maintenance costs - Quiet - Growing market - Renewable energy can be the fuel source; green H_2	- Cheap - Existing infrastructure - Volumetric energy efficiency of diesel - Easy fuel transportation
Disadvantages	- High CAPEX - Expensive fuel - Low volumetric energy efficiency of H_2	- Emissions - More diesel required for each kW generated at part load - Rising fuel costs - Fossil fuel

3.4.3 H_2 ferry projects

Cleaner fuel recommendations for ships can be divided into suitability for short, medium and long distances, correspondingly electricity, hydrogen and carbon sourced or ammonia (Blomberg, J. 2018). H_2 for transport fuel would be most suitable for commuting ferries, which don't need many days of storage capacity on board. A diesel ferry can be converted to a H_2 ferry by replacing diesel engines with fuel cells, requiring only small changes into the power distribution system.

The most common fuel cell system is based on PEM technology due to advantages in technological development, system size and price in comparison to SOFC. Current capital expenses lie around ~1500-3000 €/kW for the fuel cell system, which in addition to the fuel cell include AC/DC conversion, electrical works, cooling and air conditioning. Normally the system includes batteries, but supercapacitors are a smaller and more efficient alternative (Vänskä, K. 2019).

It is not a new invention to use fuel cells in ferries. It has been considered for decades (Pratt, J.W. & Klebanoff, L.E. 2016). There are several ongoing demonstrations with H_2 ferries. VTT is continuously doing research in the H_2 transportation field and in the MARANDA project, financed by the Fuel Cells and Hydrogen Joint Undertaking where an emission-free hydrogen fueled PEM fuel cell powertrain system is validated in demanding arctic conditions (FCH JU. 2017). Commercial service fuel cell vessel projects in Europe include for example FCS Alsterwasser, NemoH2, Hydrogenesis and E4ships (Pratt, J.W. & Klebanoff, L.E. 2016). A few most recent H_2 ferry projects are shortly presented in the subchapters below.

3.4.3.1 HySeas III

Ferguson Marine, in consortium with international research and manufacturing companies, is developing world's first renewables-powered H_2 car and passenger ferry, HySeas III, which will be operating in Orkney, Scotland. Estimated supported development costs are 12,6 M€. The vessel's H_2 fuel will be produced from RES through electrolysis making water the only residual when running the ferry. (Ferguson Marine. 2018)

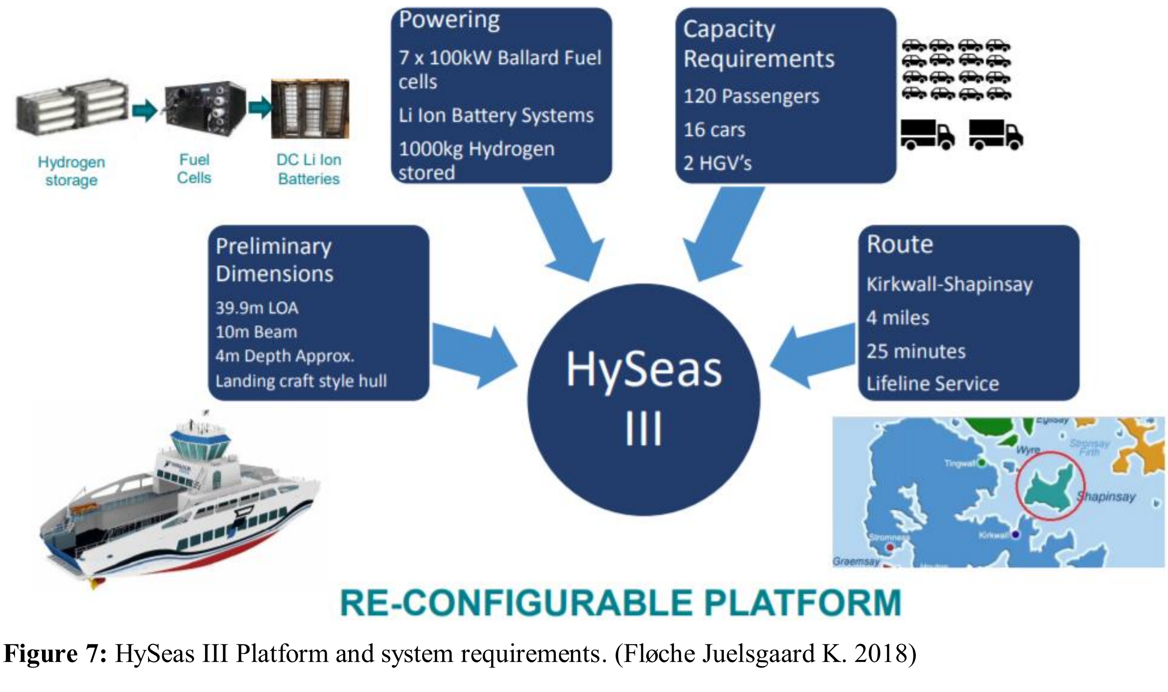

Figure 7: HySeas III Platform and system requirements. (Fløche Juelsgaard K. 2018)

The HySeas III Platform will consist of components with function requirements as presented in Figure 7 above.

3.4.3.2 SF-BREEZE

SF BREEZE (San Francisco Bay Renewable Energy Electric vessel with Zero Emissions) is a liquid H_2 (LH_2) fueled high speed 150 passenger ferry in the San Francisco Bay. The total installed power consists of 41x120 kW PEMFC racks, each 4x30 kW, reaching a top speed of 35 knots (64,8 km/h). One passage of 44,5 km takes ~55 min. The estimated construction costs of the vessel are 21,99 – 29,22 M$, which mainly depend on the PEMFC CAPEX. The fuel cells and fuel storage system will be above deck due to regulatory and safety constraints (Tronstad, T. et al. 2017). The ferry is still in planning state but "*commercially, the SF-BREEZE has a promising future*". (Pratt, J.W. & Klebanoff, L.E. 2016)

Hydrogen costs from renewable compressed gas depend on the consumption volumes. The feasibility study of the SF-BREEZE, by Joseph W. Pratt and Leonard E. Klebanoff, compares in Table 10 the costs of H_2 as fuel depending on the production method.

Table 10: H_2 costs at production based on natural gas vs. renewable energy. (Pratt, J.W. & Klebanoff, L.E. 2018)

	Low volume (< 50-200 kg/day)	Medium volume (200-600 kg/day)	High volume (> 600 kg/day)
Fossil Natural Gas – Compressed H_2	7,90 €	5,27€	4,78
Renewable – Compressed H_2	13,92	9,27€	8,44€

3.4.3.3 MF Ole Bull

The Osterøy car ferry *MF Ole Bull* will be the first H_2 fueled car ferry in Norway. CRM Prototech is planning to replace one of the two existing diesel engines with an electric motor consisting of 200 kW PEM fuel cells and 100 kWh batteries. MF Ole Bull will run between Valestrand and Breinstein, north of Bergen. A smaller but similar system was tested on *MF Vågen*, providing the foundation for the new project. The estimated daily H_2 consumption is 150 kg. Safety of H_2 as fuel vs. conventional diesel is still being investigated. (CMR Prototech. 2018)

The costs of 542 000 € (5,25 million NOK) for transforming MF Ole Bull into a hybrid ferry will be financed by Enova. However, the rebuild will save around 100 000 € annually. The target is to run the ferry in hybrid mode by the end of 2019 and total H_2-electric mode by 2021 or 2022. (Transport & Logistikk. 2018)

3.4.4 Fuel cells for ferries

For on-board applications, PEMFCs currently have the highest potential, out of the commercialized fuel cells, due to their high energy density, size and weight benefits, short start-up times and ability to be stacked endlessly in order to obtain the desired power output. However, CAPEX are still high and vary a lot, 1000-3000 €/kW (IEA. 2015, Burgren, J. 2019; Tröger, M. 2019) for prototypes and ~450 €/kW (IEA. 2015) for fuel cell electric vehicles. CAPEX is expected to decrease considerably with wider up-scaling economies commercialization. (Goodwin, A. 2015)

Due to the reasons above, only PEMFCs are considered for ferry applications in this study.

4 H_2 as part of the Åland energy system

Due to the large shift in energy production towards electricity self-sufficiency on Åland, with emphasis on VRES, the alternative of including H_2 for flexibility will be investigated. The focus will be on fueling ferries with own produced H_2 from excess VRE production.

There are annually approximately three periods of six days with no wind or solar power production during these periods, we have a peak capacity of 85 MW in 2030 (Nikzad, D. 2018). The average daily electricity consumption in 2030 on Åland is ~1,033 GWh, based on the annual consumption predictions by Kraftnät Åland (Mörn, J. 2018). In order to cover one week's, seven days', energy demand, we would need 7,23 GWh of stored energy for total island mode. Power-to-H_2-to-power has currently an efficiency of below 30%, which makes H_2 for large scale storage not necessarily profitable. The trend today is to favor interconnections as set in the EU *electricity interconnection target*, where all member states of the union are called to achieve interconnection of at least 10% of their installed production capacity by 2020 (European Commission, 2015). Therefore, and due to the existing cable connections to Sweden and mainland Finland, a total independency is not necessary and profitable at this stage.
Cables:

- Åland – Finland: length 161,8 km (Saari, P. et al. 2019), losses 10%
- Åland – Sweden: length 62,9 km (Saari, P. et al. 2019), losses 2%

Wind has properties of a base load during winter-season. Large amounts of solar power would stand for the same during summer-days. (Fortum. 2017)

Two different electricity production scenarios and corresponding H_2 production scenarios are presented in the sub sections 4.1.1 and 4.1.2 below. We assume here the costs of local power production to be at zero. The fuel cell system for ferries and the production of gaseous H_2 itself are being discussed as separate businesses in this study.

4.1 Set-up of scenarios

The analysis was conducted through two different production scenarios: Scenario 1, Biomass Baseload Scenario, and Scenario 2, High-Wind Scenario. These scenarios have been agreed to during the FLEXe Demo phase of the project (Saari, P. et al. 2019).

The demand profile is based on the electricity consumption predictions of KNÅ with a 1,4% increase annually, 1,5% increase 2028-2040 (Mörn, J. 2018) and historical electricity consumption data (ÅSUBs-PX Web databaser. 2017). The demand distribution of the annual energy consumption is approximated according to Figure 8 below. This distribution is used for all years in this study.

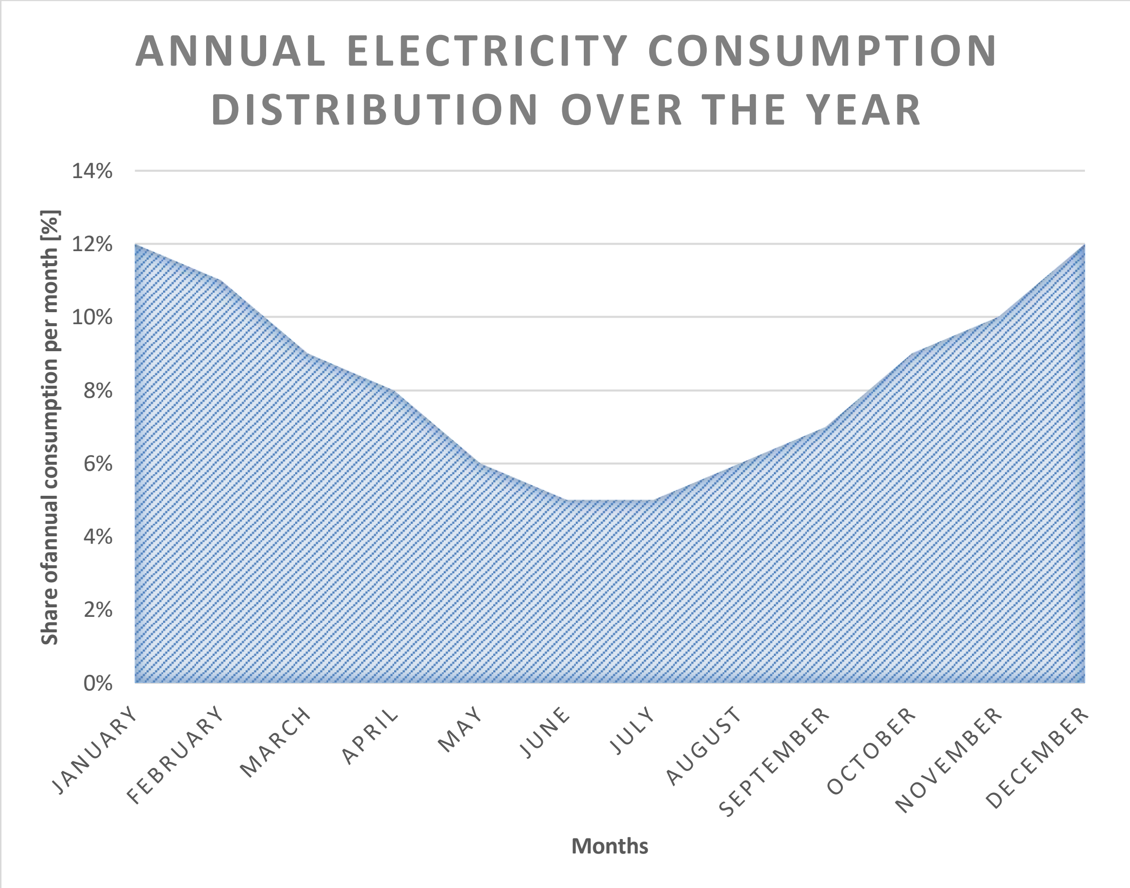

Figure 8: Assumed distribution of the electricity demand in percent over the months of a year (Fortum. 2019)

The production scenarios, their corresponding assumptions for the energy production and potential of remaining electricity for gaseous hydrogen production are presented in the sub-sections below.

4.1.1 Production scenario 1 – "Biomass Baseload Scenario"

The power production capacity, a corresponding electrolyzer capacity and its data sources and assumptions summarized in Table 11 below.

Table 11: Summary of the electricity production capacity and corresponding H_2 production capacity for scenario 1 – "Biomass Baseload Scenario".

Production	Capacity (year of commissioning)	Assumptions for energy production
Wind (onshore)	21 MW (existing) 39 MW (2020) 15 MW (2021) 15 MW (2025) Total: 90 MW	Based on annual historical wind power production data from 2016-2018 proportional to the capacity increase and annual variations during the years 2016, 2017 and 2018 (Mörn J. 2016). Since the wind power of today in Åland is "offshore on the rocks", no difference in the energy generation capacity between on- and offshore has been considered.
CHP Biomass	20 MW (2022)	Assumed full load October-March, half load April and September, One third load May-August. Based on an average on annual load assumptions of 6060 h per year (Pääkkönen, A. & Joronen, T. 2019).

Solar PV	15 MW (2022)	Based on monthly sun-hours on Åland (World Weather & Climate Information. 2019) , battery efficiency 80%, Inverter efficiency 90%, grid losses 10% and performance ratio 75% (Wirth, H. 2018) and comparison to previous analysis done by Fortum (Fortum. 2017).
Electrolyzer	2 MW	The size of the electrolyzer is adapted to the production of H2 for the reference ferry only and will be run continuously with either own produced or imported electricity. The total cost of ownership is assumed to be lower in continuous use and adapted size of the electrolyzer. CAPEX and storage costs can be minimized but more costs appear when importing electricity.

This scenario is based on gaseous H_2 production only for the potential H_2 driven fuel cell ferry. Figure 9 demonstrates the flows in scenario 1.

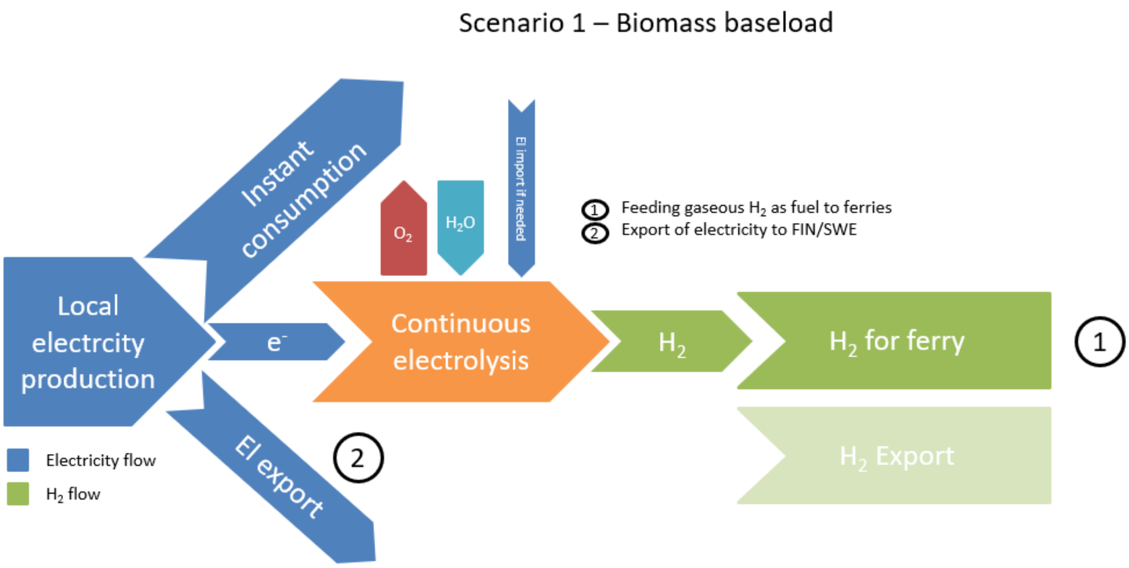

Figure 9: Graphic presentation of the use of produced excess renewable power in scenario 1. The electrolyzer is sized to the H_2 demand of the ferry and the resting potential excess power is exported. In case of not enough local energy production, electricity is imported to keep the electrolyzer running continuously. There is no export or other use of H_2 in this scenario.

In scenario 1, the Biomass Baseload Scenario, the highest surplus occurs in October with high winds and not yet too high heating demand in the years 2025 and 2030, Figure 10. On an annual scale, the actual highest surplus eventuates in 2026. When looking only at monthly surpluses, Figure 11, the years with the highest energy surplus are between 2025 and 2030. Due to the increase in demand, but no capacity increase after 2025, the remaining energy decreases the following years thereafter. From 2030 onwards, the investments in energy capacity will not generate surplus energy for H_2 production.

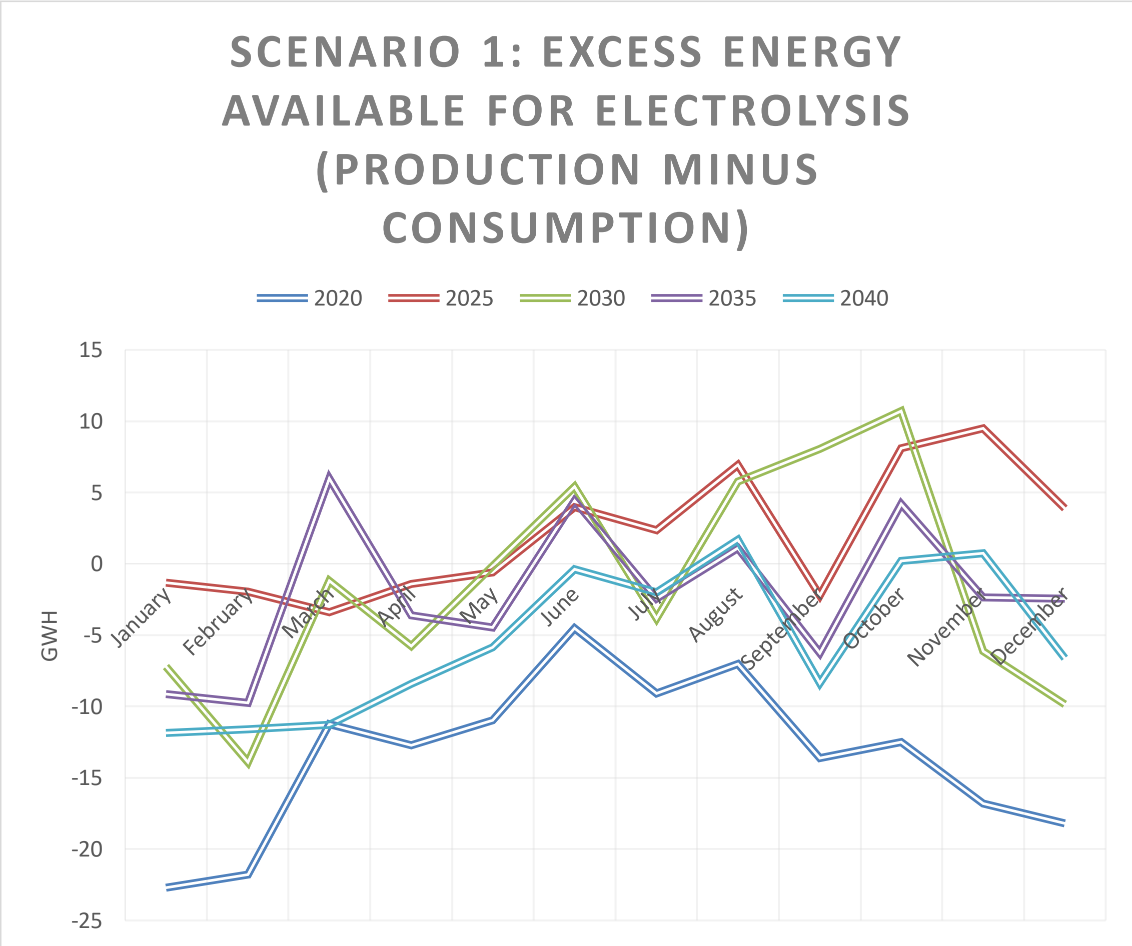

Figure 10: Monthly energy balance in the production scenario 1 after the consumption.

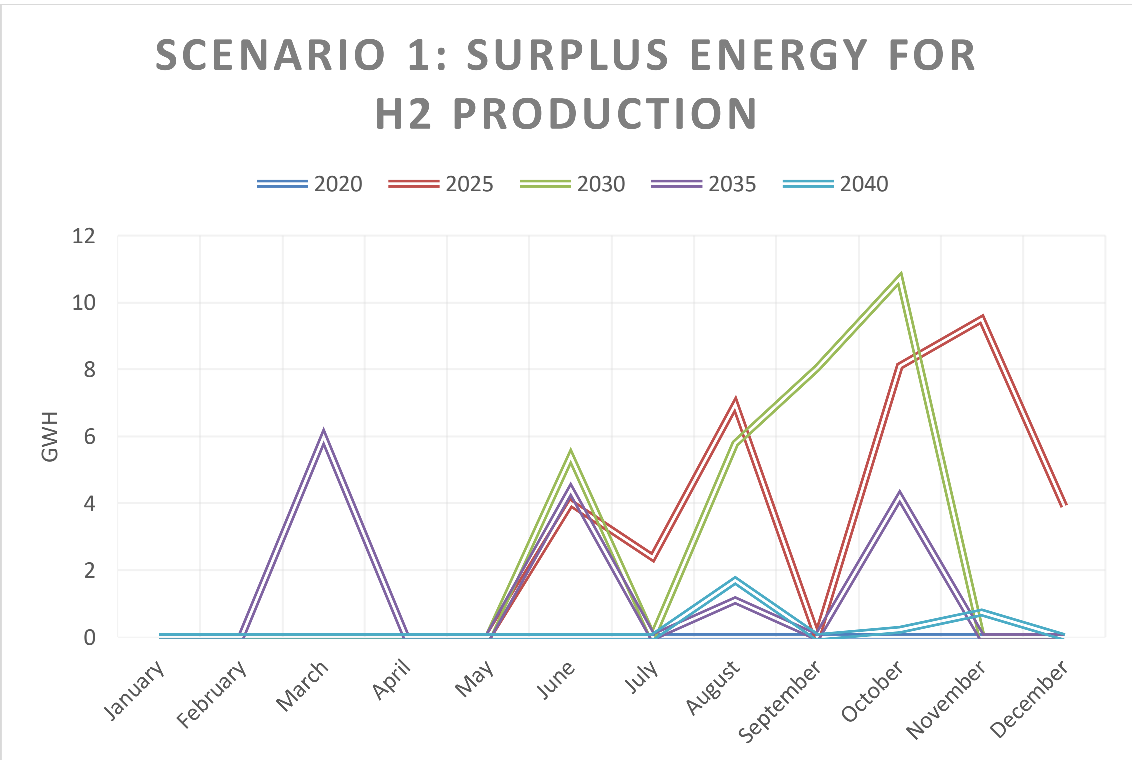

Figure 11: Monthly energy surplus in scenario 1 after the consumption.

Since it is not possible to add more biomass capacity to Åland, due to the restrictions in biomass fuel (Pääkkönen, A. & Joronen, T. 2019), either solar or wind capacity could be added to meet the electricity demand. In order to have an annual positive energy balance during the years 2030-2040, it would require i.e. 25 MW more wind power capacity or 20 MW of wind and 15 MW of PV.

4.1.2 Production scenario 2 – "High-Wind Scenario"

The difference is in scenario 2 compared to scenario 1:

- \- Biomass
- \+ Offshore wind
- \+ 5 MW Solar
- \+ Larger electrolyzer (adapted to the excess electricity produced)

The power production capacity, a corresponding electrolyzer capacity and its data sources and assumptions summarized in Table 12 below.

The aim with a larger electrolyzer is to potentially export more valuable H_2 instead of cheap electricity, which already has an evolved market. H_2 on the other hand may have a rising value with an increasing demand. Alternatively to exporting H_2, it could be used locally e.g. when extending the H_2 transportation sector or in SOFC in houses to produce both heat and power.

Table 12: Summary of the electricity production capacity and corresponding H_2 production capacity for scenario 2 – "High-Wind Scenario".

Production	Capacity (year of commissioning)	Energy production
Wind (onshore)	21 MW (existing) 39 MW (2020) 15 MW (2021) 15 MW (2025) Total: 90 MW	Based on annual historical wind power production data from 2016-2018 proportional to the capacity increase and annual variations during the years 2016, 2017 and 2018 (Mörn, J. 2016). Since the wind power of today in Åland is "offshore on the rocks", no difference in the energy generation capacity between on- and offshore has been considered.
Wind (offshore)	100 MW (2030)	
Solar (PV)	20 MW (2022)	Based on monthly sun hours on Åland (World Weather & Climate Information. 2019) , battery efficiency 80%, Inverter efficiency 90%, grid losses 10% and performance ratio 75% (Wirth H. 2018) and comparison to previous analysis done by Fortum (Fortum. 2017).
Electrolyzer	2 – 48 MW (See Table 21)	The size of the electrolyzer is adapted for the production of H2 from large amounts of excess electricity and will be ran when local excess electricity is available. During longer periods with no wind, the electrolyzer will be powered down.

This scenario is based on gaseous H_2 production for the potential H_2 driven fuel cell ferry and for export. Figure 12 demonstrates the flows in scenario 2.

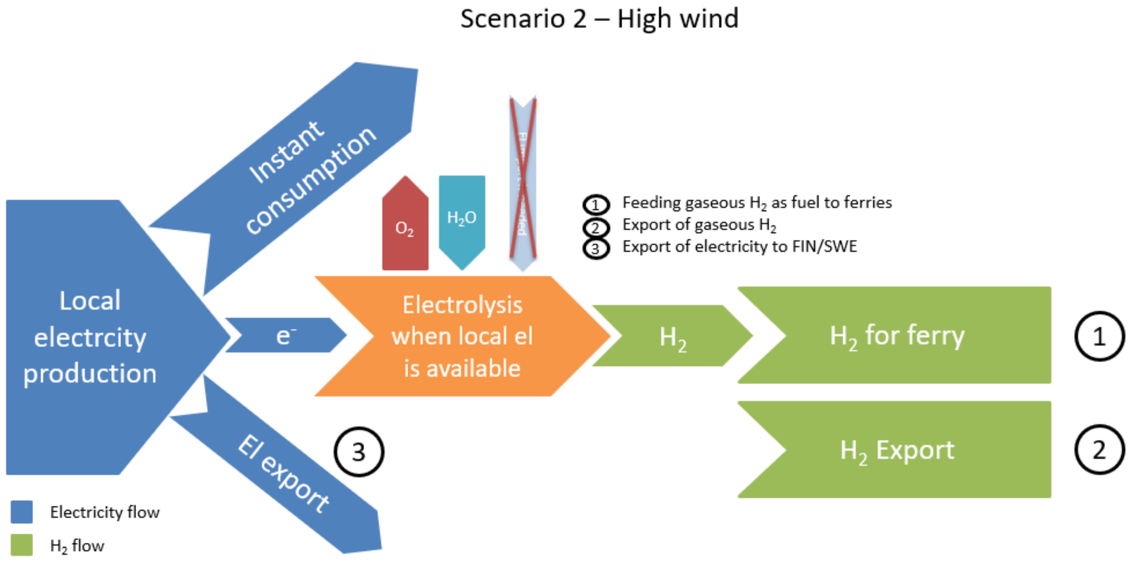

Figure 12: Graphic presentation of the use of produced excess renewable power in scenario 2, where the amount of produced electricity in 2030 is assumed to be larger than in scenario 1. The electrolyzer capacity is sized to different degrees of hourly excess wind power production. First, the excess power goes to produce H_2 fuel for the ferry. Secondly, to the maximum H_2 production capacity of the electrolysis for H_2 export. Thirdly, the remaining electricity is exported.

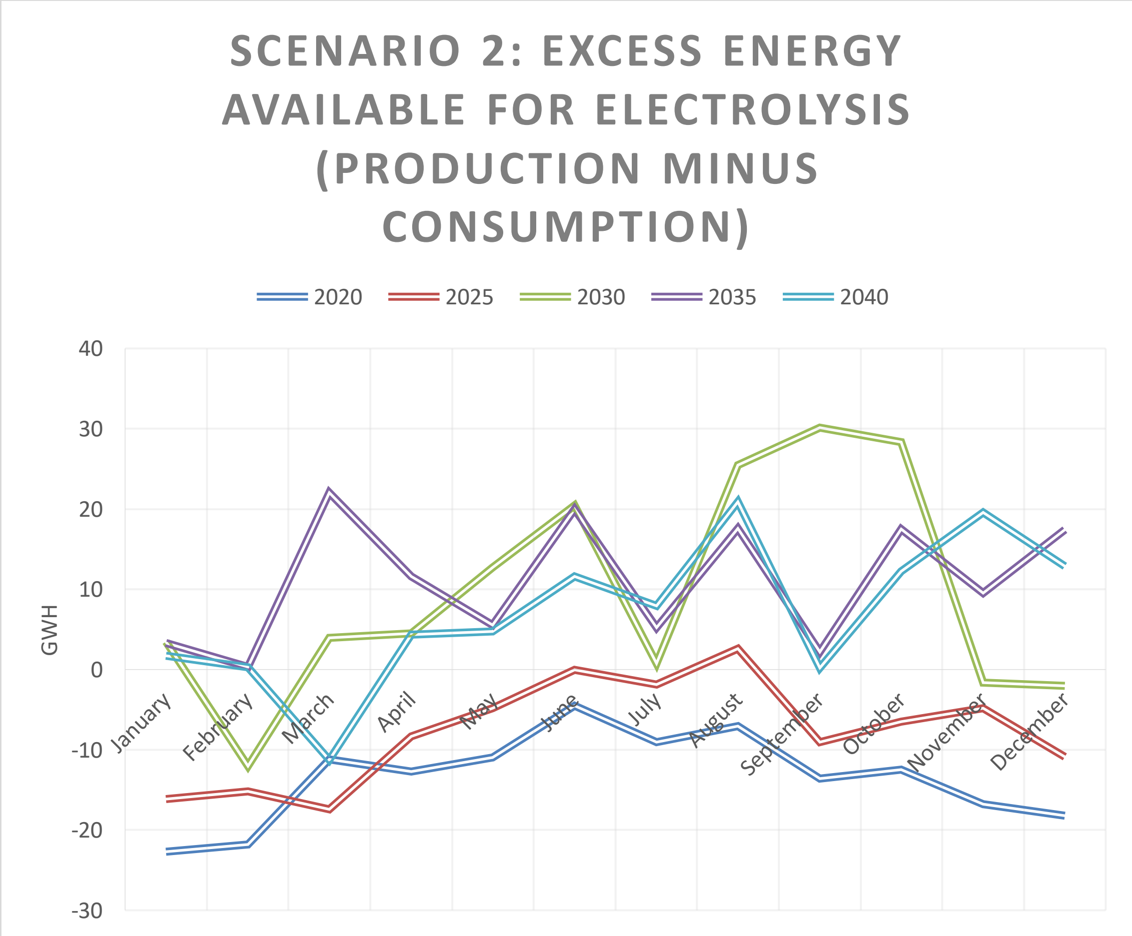

Figure 13: Monthly energy balance in the production scenario 2 after the consumption.

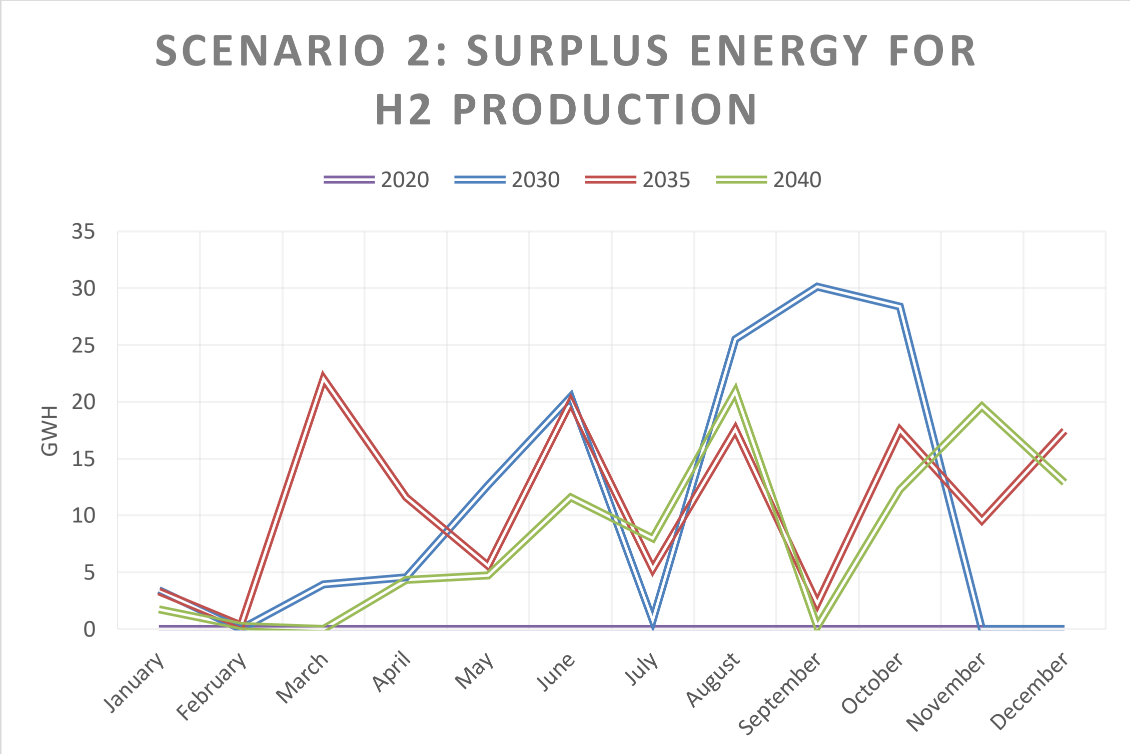

Figure 14: Monthly energy surplus in scenario 2 after the consumption.

The monthly energy balances, Figure 13, and surpluses, Figure 14, for the production scenario 2, the High-Wind Scenario, show a clear surplus after 2030 after the commissioning of 100 MW new offshore wind capacity. As in scenario 1, the total positive energy balance reduces annually after commissioning of the last new capacity due to increasing consumption.

There is no annual surplus energy before the construction of 100 MW offshore wind capacity in 2030. However, the following years 2030-2040 there will be a significant surplus of electricity, which could be exported as electricity or H_2.

68 MW instead of 100 MW offshore wind capacity would be enough to result in a positive energy balance until 2040 but still with a remarkable surplus during 2030-2035.

Tabulated values for both monthly energy balances and remaining surpluses attached in Annex 1.

4.2 Gaseous H_2 for ferry operation and potential export

On Åland there are several ferry routes, which could be fueled by H_2. There are ongoing investigations for driving the wire-ferry between Töftö and Prästö with gaseous H_2 fueled fuel cells (Nordlund, E. 2019). In this analysis the Svinö (mainland Åland) – Föglö (Degerby) route was used as reference, since it has been investigated the most and has available data due to the ongoing tender. The data in Table 13 has been used for the calculations for the H_2 consumption of the ferry.

Table 13: Specific route and ferry information of potential ferry, Svinö – Föglö (Degerby), to be driven by gaseous H_2. (Karlman, N. 2018) (Ålands Landkspsregering. 2018) (Smirnov, A. & Pasinen, R. 2018)

Svinö – Föglö route	
One-way distance	8,5 km
Passages / day	26
Passage time	20 min
Max passenger capacity	350 persons (on average 120) 90 cars
Power output	1’200 kW
Annual consumption	2’847 MWh/year
Consumption	35,3 kWh/km
Daily consumption	7,9 MWh/day

The power demand of the ferry between Svinö and Föglö varies during the start and slow down during the different weather conditions. There are 26 similar passages each day.

Between every passage there is at least a break of 10 min and several longer breaks, 30 min, 1h 10 min, 1h 20 min, 1h 35 min, 35 min, 35 min and 6h over night (Ålands Landskapsregering. 2018). These times facilitate potential charging and refueling. One passage consumes approximately 407 kWh in winter and 287 kWh in summer (Smirnov, A. & Pasinen, R. 2018).

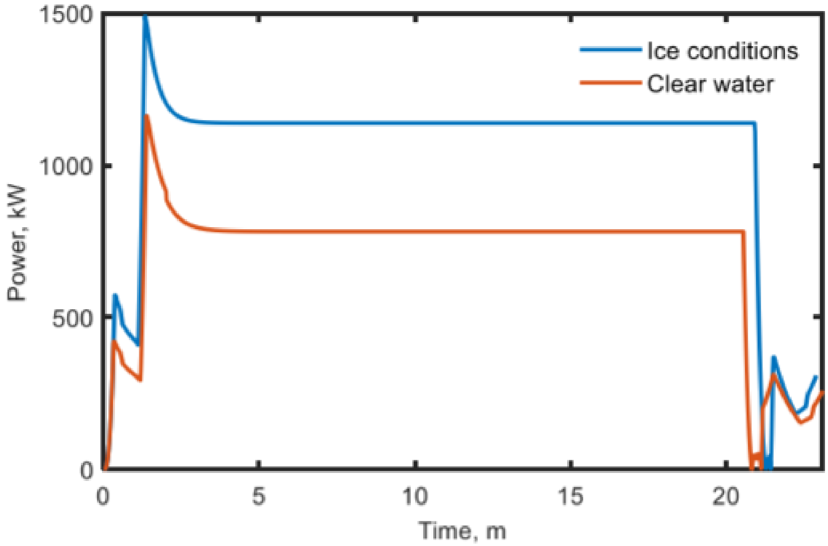

Figure 15: Power profile of the Svinö-Fögö ferry during the passage time. Peak power and cruising power in ice conditions are 1,57 MW and 1,22 MW and similarly 1,24 MW and 0,862 MW during summer. (Smirnov, A. & Pasinen, R. 2018)

In the calculations we assume an average consumption of 25% less than the peak of 1,2 MW, resulting in 900 kW, which suits the plot in Figure 15. The daily time of driving in the passages becomes 8h 40 min. Due to potential extra service driving and higher loads the daily drive with marginal is assumed to be 10h. The daily electricity demand becomes then 9000 kWh.

During the course of this study, a smaller cable ferry between Töftö and Prästö on the Åland islands is being investigated to be driven by hydrogen. The capacity of this smaller ferry would be 600 kW (Nordlund, E. 2019). Downscaling from a larger ferry to a smaller one is easily possible when the other parameters remain the same.

4.2.1 Fuel Cell System

The most promising fuel cell type today is PEMFC. The fuel cell system would need to have a capacity of at least 1'200 kW divided on least on two axes. Therefore, the fuel cells could be e.g. 2 x 600kW, 4 x 300kW or 12 x 100kW.

The Table 14 below summarizes a comparison of the 1200 kW fuel cell systems of three fuel cell suppliers.

Table 14: Specifications of fuel cell properties of three fuel cell suppliers. Values are obtained directly from the fuel cell suppliers and used for calculating the resting numbers and making average approximations. Sources in alphabetical order but in the table randomized order. (Ballard. 2017) (Ballard. 2018) (Burgren J. 2019) (Hydrogenics. 2019) (Melcher, M. 2019) (Power Cell Sweden. 2018) (Pratt, J.W. & Klebanoff, L.E. 2016) (Vänskä K. 2019)

Fuel Cell (FC)	FC Supplier 1	FC Supplier 2	FC Supplier 3
Size [litres]	594 l/90 kW 1200 l/180 kW 7920 l/1200 kW	500 l /100kW 6000 l/1200 kW	300 l/100 kW 3600 l/1200 kW
Weight[9] [kg]	504 kg/90 kW 720 kg/180 kW 6720 kg/1200 kW	285 kg/100 kW 3420 kg/1200 kW	150 kg/100 kW 1800 kg/1200 kW
Elec production [kWh/kgH_2]	15	15	17
H2 consumption [kg/MWh]	68	65	59
H2 consumption [kg/h]	81	72	65
Daily H2 demand [kgH_2][10]	607	585	530
Half day H2 demand [kg]	304	293	265
Monthly demand [kgH_2]	18215	17550	15882
Annual H2 demand [ton]	222	214	193
Annual fuel cost [€][11]	1 108 058 €	1 067 625 €	966 176 €
CAPEX [€/kW][12]		1 800 €	
Total fuel cell CAPEX [€]		2 160 000 €	
Annual maintenance cost[13] [€/year]		43 200 €	
Time to major overhaul [h]		15 000 – 50 000	
Major overhaul cost[14] [€]		216 000 €	

In addition to the fuel cell power system, fuel cell stacks, the system requires balance of plant components including hydrogen tanks, sensors, environmental system, cooling system and power controlling and electrical equipment.

[9] Coolant pump and air system excluded (Supplier 2 and 3). They would lead to ~100 kg/100 kW more.
[10] Based on Ballard fuel cells. 26 rides/day à 20 min = 520 min = 8,97 h → 10 h with marginal. Assumed average capacity load 1200kW*0,75=900kW. Daily demand = 900kW*10h = 9000 kWh.
[11] Fuel cost 5€/kg (Woikoski). In reality the price of H_2 will be the CAPEX and OPEX costs of the excess wind power capacity.
[12] Average value based on received price ranges from fuel cell supplierss. Prices would vary with size, wherefore it is not possible to make an exact price conclusion according to these prices.
[13] OPEX 1-2% out of the CAPEX costs (Pratt, J.W. & Chan, S.H. 2017). Here 2 % was used.
[14] Suppliers stated major overhaul costs vary to vary 5-15% of CAPEX. Here 10 % of CAPEX was assumed.

Fuel cells are assumed to have zero emissions since the H_2 will mainly be produced from emission-free energy sources. In case of electricity import from Sweden, the electricity is also mainly produced through hydro power. When comparing to diesel engines, there are NO_x, CO, HC, OM, SO_x and CO_2 emissions. Table 15 presents the amount of avoided direct emissions and their value when using a fuel cell instead of a diesel engine. The societal cost includes environmental and health damage.

As a result from the savings in emissions, the social benefit of using fuel cells instead of diesel engines becomes ~465 300 €/year. This is only one way of calculating the societal cost caused by emissions and the spread is large when comparing different sources.

Table 15: Socioeconomical benefit of avoiding emissions in the operation of a fuel cell ferry compared to a conventional ferry. Assume the fuel cell ferry does not emit any greenhouse gases.

Emissions type	Avoided emissions [ton/a][15]	costs of emissions [€/ton][16]	Social costs [€/year]
CO_2	2670	44,0	130 800
CO	8,10	444	3 600
HC	2,60	3 600	9 360
NO_x[17]	27,7	5 200	144 000
PM	1,36	130 000	176 800
SO_x	0,0231	34 800	800
Total social costs [€/year]			465 300

Avoiding NOx, PM and GHG emission associated with operating the ferry result in societal economic benefits. In the SF BREEZE, over the 30-year lifetime of the ferry, the benefit is estimated to be 2,6 – 11 M$ (Sandia. 2016)

Roughly comparing the total annualized costs of a fuel cell and a diesel engines, it becomes clear from Table 16, Figure 17 and Figure 18, that after four years, the fuel cells become cheaper than the diesel engines. Fuel costs are the biggest annual cost in both fuel cell and conventional ferries. This analysis only includes the fuel cell and generator component. In a H_2 fueled ferry, especially the installation costs and training for a new system would also cause significant costs. Diesel engines are not able to distribute their load to reduce the number of annual operational hours, whereas fuel cells have a control system able to reduce the number of stacks in operation to meet the load demand and reducing operational hours (Pratt, J.W. & Chan, S.H. 2017). Therefore a 20 % higher number of operational hours per day is assumed for diesel engines compared to fuel cells.

[15] Based on the relation between emissions and annual fuel consumption of road ferries in 2017 (Lipasto. 2017) and density of marine gas oil 0,86 kg/l (Engineering Toolbox. 2008)

[16] Based on the relation between emissions and price in Table 24 of Pratt J.W. & Chan S.H. 2017. Comparison of societal costs of emissions in articles Marten, A. L. & Newbold, S. C. 2012. and Van den Bergh, J.C.J.M. & Botzen W.J.W. 2015.

[17] Emission footprint of NO_x 48.86 g/l (Lipasto. 2017), 0,004 g/l (Ruf, Y. et al. 2018), 43 – 53 g/l (Pratt J.W. & Chan S.H. 2017). Emission factor of 24 g /l assumed in this case.

Table 16: Comparison of average annualized costs and NPV for fuel cell stacks and diesel engines, both with the capacity of 1200 kW. The values refer to Table 14 above. Only the fuel cell and generator components are assumed. Annualized costs refer to the CAPEX and major overhaul expenses and annually occurring expenses distributed over a specific time frame. Training and installation costs would increase the total cost of ownership of a fuel cell ferry. Fuel cell suppliers stated major overhaul costs to vary 5-15% of CAPEX. The time to major overhaul, 15 000 – 50 000 h also varies a lot in guaranty between different suppliers. Here 20 000 h to major overhaul was assumed for fuel cells and 18 000 h for diesel engines (Räsänen J-E. 2019) with a cost of 10 % of CAPEX. The rent for other investments was assumed to be 10%. (Burgren, J. 2019) (Hydrogenics. 2019) (Melcher, M. 2019) (Pratt, J.W. & Klebanoff, L.E. 2016)

Engine	Fuel Cell[18] (Average)	Diesel engine
CAPEX [€]	2 335 500 € (incl. storage)	924 000[19] €
OPEX [€/year]	43 200 €	35 040[20] €
Fuel costs [€/year]	1 047 300 €	940 900[21] €
Societal costs [€/year]	-	465 300[22] €
10 years		
Major overhauls	1	2
NPV	-2 754 000 €	-1 200 000 €
NPV (with social costs)	-2 754 000 €	-4 059 000 €
Annualized costs[23] [€/year]	1 347 000 €	1 553 000 €
15 years		
Major overhauls	2	3
NPV	-2 904 000 €	-1 269 000 €
NPV (with social costs)	-2 904 000 €	-4 808 000 €
Annualized costs [€/year]	1 277 000 €	1 522 000 €
20 years		
Major overhauls	3	4
NPV	-2 993 000 €	-1 314 000 €
NPV (with social costs)	-2 993 000 €	-5 275 000 €
Annualized costs [€/year]	1 242 000 €	1 506 000 €

Not considering social costs results in a lower negative NPV, which becomes clear in Table 16. In case social costs would be addressed to the party causing them, fuel cell ferries would be a cheaper alternative compared to conventional ferries. Normally, in investment decisions, the alternative with the lowest NPV is chosen because we expect higher profits. In this case we choose the NPV with the lowest costs. However, the calculations include uncertainty due to CAPEX assumptions (footnote 12) and assumptions made on social costs obtained from literature (footnote 15 and 16). A political agreement between different actors is necessary for consistent and stable costs.

The annualized costs, demonstrated graphically in Figure 17 and Figure 18, are calculated based on the initial investment and annually occurring costs, such as OPEX, fuel costs and major overhaul costs every 20 000 h of operation for fuel cells and 18 000 h for diesel engines. These figures demonstrate the costs per year without rent rates with CAPEX occurring once and divided by

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[18] Averaged values of the properties and fuel costs in Table 14.

[19] Tank costs not included in the diesel engine costs since they are assumed to be part of the ferry architecture itself. CAPEX costs of diesel engines assumed to be ~700 €/kW (N.N. Ship diesel engine supplier. 2019).

[20] 1€ /cylinder/ operating hour (Räsänen, J-E. 2019). 20 % higher operational hours than fuel cells assumed due to the properties of adapting operational hours to the load of fuel cells (Pratt, J.W. & Chan, S.H. 2017). 10 h → 12 h. The current plan for the Svinö-Föglö route would have 8 cylinders (Ålands Landskapsregering. 2019).

[21] MGO consumption 250 g/kWh (Ålands Landskapsregering. 2019) or 200-220 g/kWh (Räsänen, J-E. 2019). Fuel costs for ferries are ~1€/kg (Ruf, Y. et al. 2018) . 220 g/kWh is used in these calculations.

[22] Total societal cost from Table 15

[23] Annual costs include the initial CAPEX / number of years + OPEX and fuel costs every year, and annual overhaul after the operation times of 20 000 for fuel cells and 18 000 for diesel engines.

number of operational years plus additional annual costs, such as OPEX, fuel costs, social costs and potential major overhaul costs. The NPV is calculated using the formula:

$$NPV = \sum_{t=i}^{n} \frac{R_t}{(1+r)^t}$$

where n is the number of time periods, t the current year period, R_t the net cash inflow-outflow during the time period t and r the discount rate that could be earned in alternative investments (Investopedia. 2019).

NPV is used for regular investments, where social costs are not included since they are not paid by the companies doing the investments and discounting social costs is not reasonable. However, to demonstrate the impact social costs could have if included in the annual cash flow, NPV with social costs is included for comparison. In this case, if social costs are included, fuel cells should definitively be favored. Looking at the annualized costs, where social costs are included, fuel cells would be more profitable than diesel engines after four years of operation. Therefore the payback time is also roughly four years for fuel cells compared to diesel engines. From a political and social perspective, social costs should be included in the cost analysis but the question is who would stand for these social costs. Subventions on the initial capital expenses of fuel cells or additional social costs to diesel engine investments could increase to profitability of fuel cell ferries. Figure 16 demonstrates how reducing the price of the initial fuel cell CAPEX affects the NPV. In order for fuel cell investments to reach a similar NPV as for diesel engines (excluding social costs), the fuel cell CAPEX needs to reduce by 60-70%. Experience from price reductions in photovoltaics and on- and off-shore wind makes this target quite realistic with time.

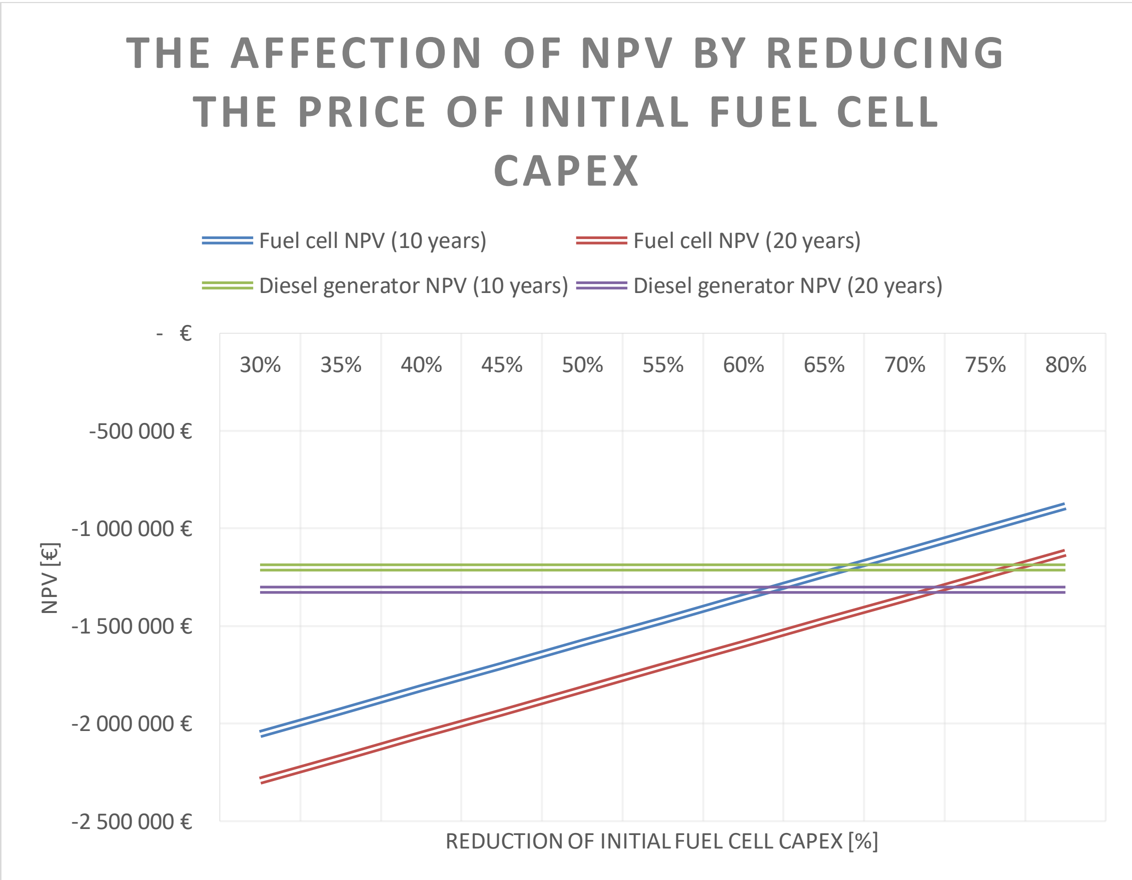

Figure 16: How reducing the initial CAPEX of fuel cells affect the NPV of a fuel cell investment. The NPV of diesel engines is included for comparison.

The low costs of gaseous H_2, 5 €/kg, could make using H_2 faster profitable in comparison to diesel. Doubling the cost of H_2 to 10 €/kg would not make the fuel cell profitable even after 20 years in this analysis. Including the CPEX of a half day storage on-board the ferry, leads to additional CAPEX of 175 500 €[24]. In addition, the costs of emissions, especially CO_2, will increase with time due to the reduction in emissions in the European Union Emission Trade System and would favor fuel cells before diesel engines.

For the time being, fuel cells have very high CAPEX, which are predicted to reduce. The United states Department of Energy predicts costs of 50 $/kW with mass production of more than 100 000 units/year (Wilson, A. & Kleen G. & Papageorgopoulos, D. 2017). However, diesel engines have been on the markets for so long that their CAPEX won't change much anymore. With a larger local production of gaseous H_2, fuel costs of H_2 for ferries could also reduce. Prices on emissions will increase as well. These potential market changes will be beneficial for fuel cell technologies.

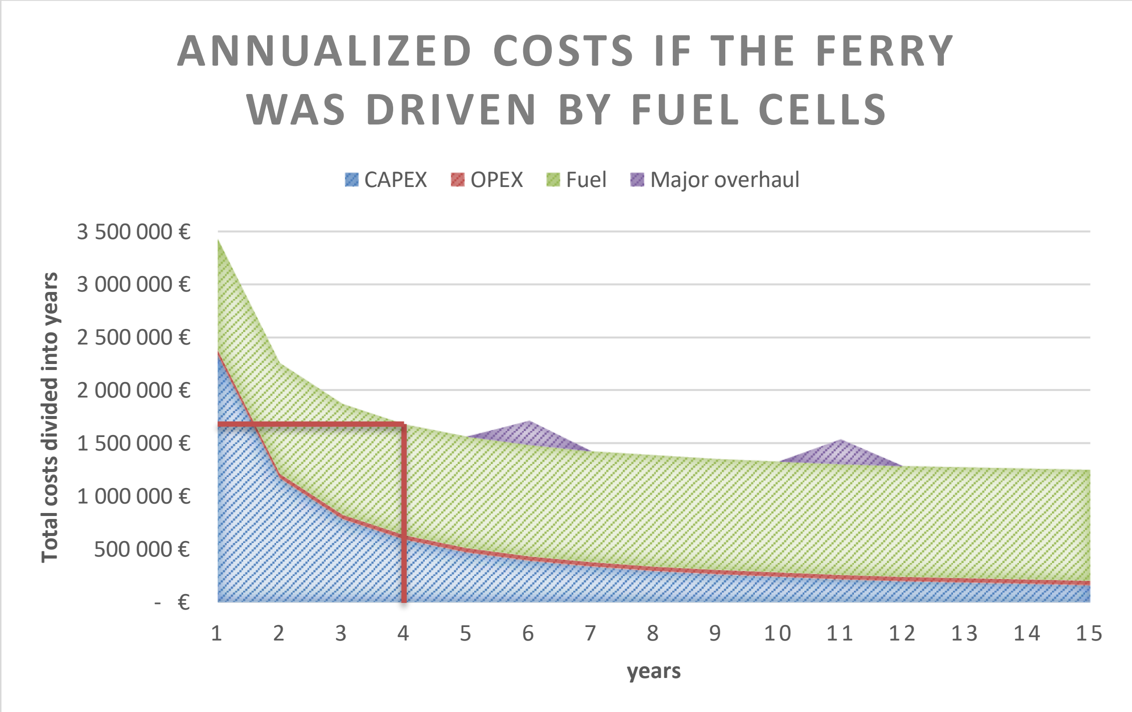

Figure 17: Annualized costs of CAPEX, OPEX, gaseous H_2 fuel and major overhaul of fuel cells when distributed over the year. Storage and fueling is not included in this analysis.

[24] Half-day on-board storage = 585 kgH_2 / 2 = 292,5 kgH_2. Costs of half-day storage = 292,5 kgH_2 * 600 €/kW (average cost of storage Table 17) = 175 500 €

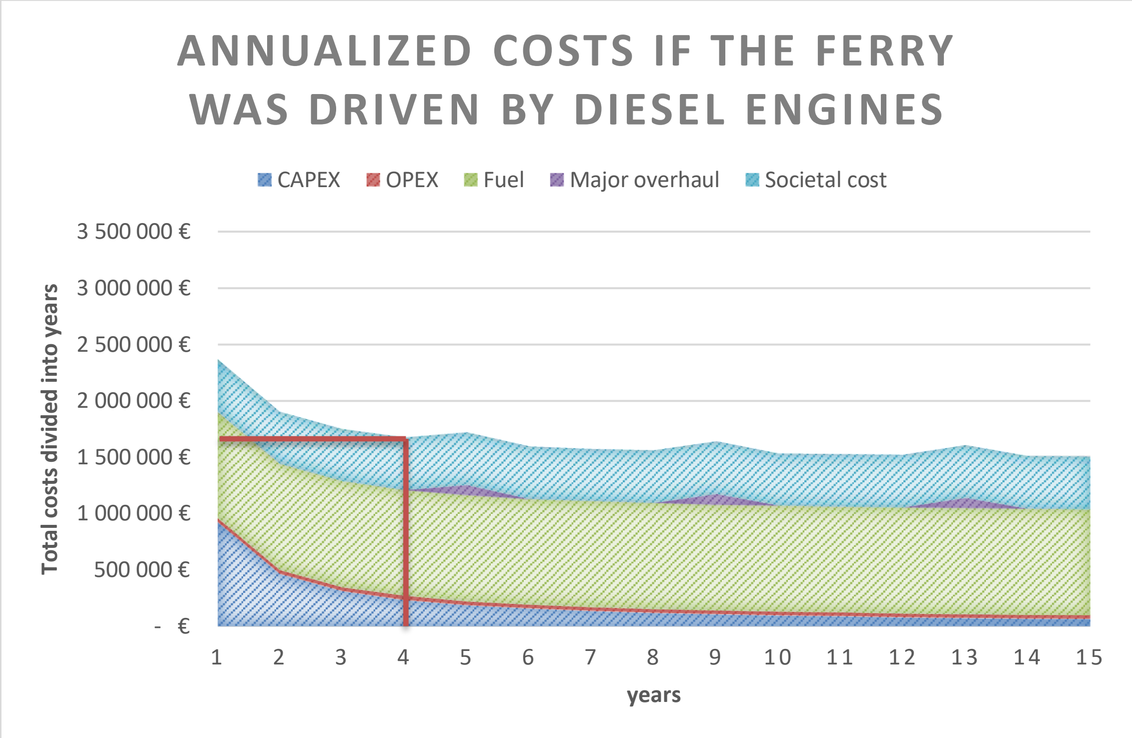

Figure 18: Annualized costs of CAPEX, OPEX, gaseous H_2 fuel and major overhaul of diesel engines when distributed over the year. Storage and fueling is not included in this analysis.

4.2.2 Ship-born Storage

H_2 can be stored on-board for the whole daily demand or partly if fueled during one of the daily breaks. There are three breaks of ~1 hour per day, wherefore e.g. twice per day fueling is fully possible. Due to the heavy weights, large volumes and CAPEX costs of the storage system, the storage size is adapted to half-day use. Fueling hydrogen does not require more time than conventional refueling.

The most suitable H_2 storage for ferries currently seems to be composite cylinder bottles (Vänskä, K. 2019). Table 17 below summarizes a comparison between cylinder storage types suitable for ferries and ships from four different suppliers. The storage is assumed for half-day H_2 demand.

Table 17: On-board H_2 storage system comparison between four different suppliers regarding i.e. quantity of bottles and system weight, volume and approximate costs of composite cylinders. Sources in alphabetical order but in the table randomized order. (Chiron, R. 2019) (Fredheim, V. 2019) (Hexagon. 2017) (Ismar, M. 2019) (Olsen, O.M. 2019)

Half-day (292,5 kgH2)[25]	Storage Supplier 1	Storage Supplier 2	Storage Supplier 3	Storage Supplier 4	Storage Supplier 5	Storage Supplier 6
Model	20-ft ISO container Type I	Reference F Type IV	Magnum 2 Type IV	20” 300 bar	10” 500 bar	40” ISO Standard Type IV
Pressure [bar]	300	350	250	300	500	350
Tank properties	150 l 3,2 kgH2	112 kg 350 l 8,4 kgH2	267 kg 1 170 l 21,04 kgH2	114 kg 330 l 7,6 kgH2	114 kg 330 l 22,9 kgH2	1 420 kg 1 700 l 40,8 kgH2
Quantity of tank cylinders	92	35	14	48	48	8
System weight [ton][26]	7	3,9	3,8	5,8	6	11,4
Water volume [m^3]	13,5	12,3	16,4	26,2	13,1	13,1
Material	stainless steel	Full carbon polyethylene	Full carbon polyethylene	Composite Type 4	Composite Type 4	Fiberglass
CAPEX /kgH2 capacity	412 €	600 €	600 €	783 €	729 €	400 €
Total CAPEX	120 370 €	176 400 €	176 736 €	288 350 €	368 874 €	117 000 €

All suppliers in Table 17 stated an “unlimited” lifetime. For the total system volume, the water volume needs to be doubled since there has to be gaps between the bottles and rigid support structures. Water volumes range around 20-30 m^2 when pressures are 350-500 bar. CAPEX is on average ~600 €/kgH_2 capacity. Average annual OPEX are 3 000 €/system when long term maintenances are included.

The system weight varies a lot depending on the material used. Steel cylinders are long-lasting if corrosion issues are handled properly. Carbon fiber based cylinders do not well tackle with fire tests without a pressure relief or thermal relief valve. Also galvanic corrosion might be an issue in sea conditions. Fiber glass cylinders perform well on fire and impact tests without relief devices but are heavier than carbon fiber. (Olsen, O.M. 2019)

The weight of the storage system will vary depending on the material, size, pressure degree and type of the tank cylinders. On average, the weight is ~6-7 ton. Additional weight of ~10 ton comes in addition due to steel structures and pipework (Ismar, M. 2019).

[25] Ballard fuel cells. 13 rides/half-day à 20 min = 260 min = 4,33 h → 5 h with marginal. Assumed average capacity 1200kW*0,75=900kW. Required amount of H_2 =5h*900kW*65kgH_2/MWh = 292,5 kg. (Vänskä, K. 2019)

[26] Total weight of the containers + gas storage. Additional weight of ~10 ton is then caused by steel structures and pipework. (Ismar, M. 2019)

Similar storage will be used in case the gaseous compressed H_2 would be stored for weekly or monthly time periods for export or other use. Gaseous H_2 stored in bottles is easy to transport to the place and application where they are needed.

4.2.3 Electrolysis and compression

The electrolysis process can be positioned in the harbor close to the ferry since electricity transfer can easily be made through cables, whereas hydrogen would need to be transported in bottles. Electrolyzers and fuel cells are modular technology and can therefore simply be stacked up to the wished capacity (Hakala, T. 2019).

Ferries usually need min 350 bar H_2 supply, which leads to the requirement of 500 bar of the fueling station. (Ismar, M. 2019)

Alternative ways for supplying the ferry with H_2:

1. Electrolysis on site
   a. Compression to 300 – 500 bar
2. Electrolysis elsewhere (H_2 compression to 300 – 500 bar) and road transportation to the retail harbor
   a. Truck carrying 400 kg of H_2 ~30 km
3. Electrolysis elsewhere (H_2 compression to 200-300 bar) and road transportation to the retail harbor
   a. Truck carrying 400 kg of H_2 ~30 km
   b. Booster compression to 300 – 500 bar

In case of plans to add more H_2 ferries, it could be reasonable to spread out the production to several electrolyzer plants to avoid transportation. Since Åland is scattered on several islands, building pipelines to transport H_2 to different parts of the group of islands is not being considered. Least new infrastructure is needed when the transportation of gaseous compressed H_2 happens through road transportation with trucks.

One ferry consumes ~585 kgH_2 per day, as stated in Table 14, or 6504 Nm^3 H_2[27]. The losses are 3 – 4 kWh/kgH_2 in the compression 10/20 bar → 350/700 bar, which stands for losses of ~6%. The total losses in compression, storage, transmission and distribution and fueling are ~20% (IEA. 2015). The actual daily H_2 demand increases therefore to ~730 kg H_2. Figure 19 visualizes the phases and their losses between the electrolyzer and the fuel cell. The actual H_2 demand of the ferry before fueling, transport, storage and compression is collected in Table 18 with different time periods and units used in the industry. The hourly demand of the ferry is based on the daily usage of ~10 hours, whereas electrolysis can be run 24/7.

[27] $585kg_{H2} \rightarrow V_{H2} = \frac{m*R*T}{p*M_{H2}} = \frac{585kg_{H2}*8{,}31451\frac{J}{molK}*273{,}15K}{101325\,Pa*2*0{,}001008\frac{kg}{mol}} = 6504\ Nm^3$

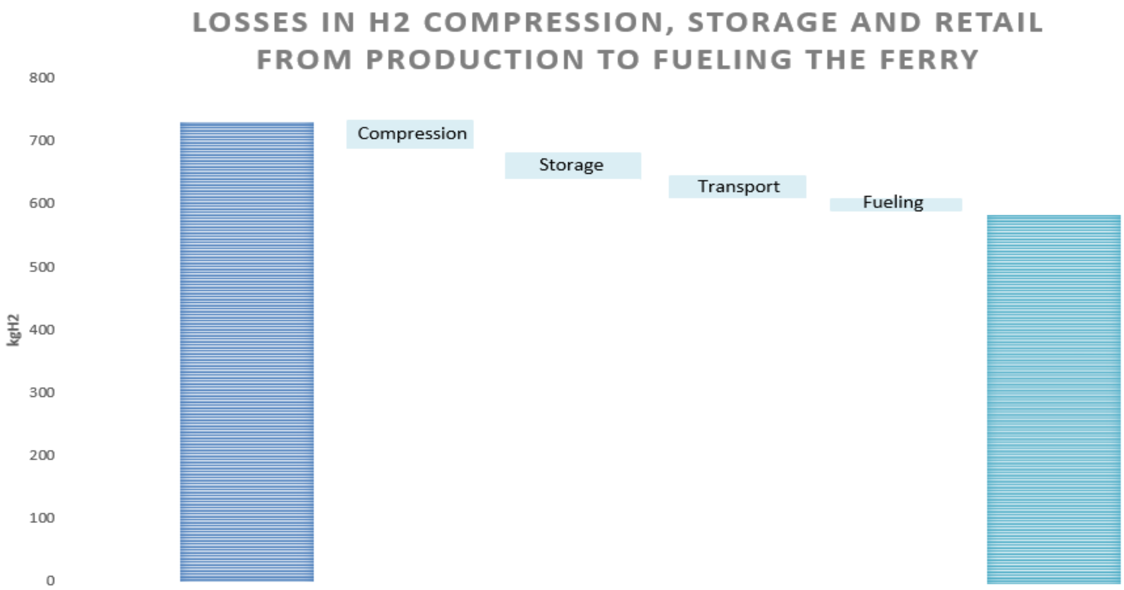

Figure 19: The actual daily H_2 energy input demand before compression, storage and retail to fuel one ferry is in reality 20% higher than the daily consumption of the ferry.

Table 18: Actual energy production demands for the reference ferry, in Table 13, on daily, monthly and annual basis based on an average electricity consumption 5,2 kWh/Nm3H2. The different units are presented since they are all used by the industry.

	One ferry / hour[28]	One ferry /day	One ferry /month	One ferry / year
kg H_2	73,1	731	22 000	267 000
Nm^3H_2	813	8130	244 000	2 970 000
MWh	4,23	42,3	1 270	15 400
GWh	0,004	0,04	1,27	15,4

When dividing the daily ferry consumption on 24 hours, the electrolyzer would have to produce 340 Nm^3H_2 / hour. Regarding the electrolysis, four suppliers with electrolyzers suitable for >340 Nm^3H_2 / hour reported properties and are being compared in Table 19. As described in section 3.1.1, only PEM electrolysis will be considered for this case.

Table 19: Electrolysis system comparison between four suppliers capable of producing H_2 from excess wind power. Sources in alphabetical order but in the table randomized order. (Braatz, C. 2019) (Hydrogenics. 2019) (Langås, H.G. 2019) (Melcher, M. 2019) (Nel. 2018) (Olsen, K. 2019)

Electrolyzer	EC Supplier 1	EC Supplier 2	EC Supplier 3	EC Supplier 4
Electricity consumption [kWh/Nm^3H_2]	5,2	5,2	4,8 – 5,3	4,9 – 5,5
Pressure [bar]	30	30	20	30
Tap water consumption [l/Nm^3H_2]	1,5	1	1,6	0,9
H_2 production	~200 Nm^3H_2/h/ MW			
CAPEX [€/kW]	950	800-1000	900-1000	900-1500
OPEX [€/year]	~2 % of CAPEX			
Cell stack lifetime [h]	80 000	61 320–87 600	80 000	60 000
Degradation [kWh/Nm^3/year]	0,05 – 0,09			

[28] Based on 10h operation / day and losses of 20 % in production

In addition to electricity, the production of gaseous H_2 also requires water. On average, the water consumption for electrolysis is 1,25 l/Nm^3H_2. The costs of water consumption is not taken into consideration in this study.

4.2.3.1 "Biomass Baseload" H_2 production – Scenario 1

In Scenario 1, the biomass baseload scenario, an electrolyzer of 1.7 MW[29], 2 MW with marginal, would be able to cover the H_2 demand of one ferry when running continuously, even in times of negative energy balance. Running continuously would increase the amount of full load hours, improving the business case. During times with negative energy balance, the electricity has to be imported. Table 20 presents the production values, costs and revenues of the electrolysis process.

Table 20: Average annual, during years 2031-2033, production of H_2 from a 2 MW electrolyzer for the reference ferry in Scenario 1. Both wind and biomass are assumed in the production but solar PV is not assumed since its role is marginal in comparison to wind power and biomass. The biomass capacity is assumed to run on 80 % all year round.

Continuous operation	2 MW electrolyzer
Total CAPEX [M€][30]	2
OPEX [€/year][31]	40 000
Peak hourly H_2 production [Nm^3H_2/h]	400
Locally produced energy for electrolysis [MWh/year]	6 555
Imported energy for electrolysis [MWh/year]	10 981
Total energy for electrolysis [MWh/year][32]	18 220
Annual produced H_2 [1000 tonnes][33]	0,315
Annual water consumption [1000 l][34]	4380
Value of the annual usable produced H_2 [M€][35]	1,26
Annual remaining electricity for export [MWh][36]	80 000
Potential revenues from remaining exported electricity [M€][37]	3,2
Total revenues (H_2 + elec) [M€/year]	4,46
Cost of import [M€][38]	~10

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29 $\frac{8129{,}6\ Nm^3H_2}{24\ h} = 340\ Nm^3H_2. Production\ capacity\ of\ an\ electrolyzer\ is\ {\sim}200 \frac{Nm^3H_2}{h\ MW} \rightarrow \frac{340}{200} = 1{,}7\ MW \rightarrow 2\ MW$

30 Assumed average CAPEX 1000 €/kW from the values in Table 19

31 Assumed average of OPEX 2 % of CAPEX in Table 19

32 Continuous operation.

33 Conversion factor 5,2 kWh/Nm^3H_2. $m = V_{H2} * p * R * T * M_{H2} = V_{H2} * 101325\ Pa * 8{,}31451\ J/molK * 273{,}15K * 2 * 0{,}001008\ kg/mol$. -20% losses from compression, storage, transportation and fueling.

34 The average of the values for tap water consumption in Table 19, 1.25 l/Nm^3H_2, is being used and kgH_2 converted to Nm^3H_2 as in footnote 25 to calculate the annual water consumption

35 Assumed the value of H_2 to be low, 5 €/kg

36 Average from the years 2031-2033

37 The SPOT prices in NordPool vary 0,01-0,06 €/kWh (Nord Pool. 2019). 0,04 €/kWh was used in this table. Assumed transmission losses 10 % (Mörn, J. 2019)

38 Total average import / year for the electricity (electricity demand + ferry variable 115 – 140 GWh / year). 0,80 kr/kWh (~0,08 €/kWh) is the price for electricity from Sweden (Mörn J. 2019).

10 981 MWh/year has to be imported to meet the demand of the ferry at all times of the year and keep the electrolyzer running continuously. With an import price of 80 €/MWh[39], the annual electricity import costs for keeping the electrolyzer running continuously become ~880 000 €.

In case of a technical failure, H_2 production gaps can be solved with existing H_2 storage since a 2 MW continuously running electrolyzer annually produces ~45 000 kgH_2 more than the actual demand of the ferry. Electrolyzer stacks are modular, wherefore a technical failure does not necessary mean a whole shutdown of the electrolyzer system.

4.2.3.2 "High Wind" H_2 production – Scenario 2

Scenario 2 requires more analysis of the export potential of electricity and H_2 in order to determine a suitable size of the electrolyzer. In the calculation of excess power remaining for electrolysis, only wind power was assumed, since it is the most significant source of electricity for Åland and there is not yet existing evidence for large scale solar production on the Åland islands. With large capacities, the role of solar could get a more important role, especially during summer. According to the potential electricity for electrolysis data for scenario 2, visualized in Figure 14 and Table 28 in Annex 1, there are a few hours during the year when the surplus energy exceeds 150 MWh. These ~10 hours occur between August and October. With adaption to larger hourly excess wind power productions, also the electrolyzer has to be bigger. Table 21 below demonstrates the required electrolyzer capacities adapted to different hourly excess wind productions. The CAPEX become extremely high when adapting to the few highest peaks. Adapting the electrolyzer to 20-50 MW seems to make sense when looking at the total CAPEX divided into operational annual hours.

Remaining excess electricity can be exported as such. Analysis on the potential revenues from the export of electricity and value of H_2 is needed for the total overview of the business potential of H_2 production from excess VRE production.

In times of no wind, Åland would still rely on cables during times of no local wind power production. Similarly as in Table 20, the negative energy balance, production minus consumption, during years 2031-2033 is averaged. This results in an import demand of ~130 GWh per year. With current electricity costs of 80 €/MWh, for the import from Sweden, annual import costs for filling the gaps with no local power production become ~10 M€. This covers both the electricity demand on the islands and the demand of the ferry. The cost would be the same independent of the electrolyzer size.

~270 000 kg of gaseous H_2 has to be produced annually, as demonstrated in Table 18, for fueling the reference ferry Svinö – Föglö. Therefore, the 2 MW electrolyzer won't be able to produce enough gaseous H_2 if not operated continuously. Therefore an additional annual cost of 880 000 €/year would occur due to an import demand of 10 981 MWh/year to keep the ferry running. 5 MW would be enough on an annual scale to keep the ferry running since it is possible to store up H_2 in bottles for times with too poor wind conditions for power production. If the 2 MW electrolyzer would be run continuously throughout the year, the potential revenues from the produced gaseous H_2 (after the consumption of the ferry) could be 1,26 M€ as in scenario 1, which is ~55 % more than if run only when excess power is available.

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[39] 0,80 kr/kWh (~0,08 €/kWh = 80 €/MWh) is the price for electricity from Sweden (Mörn J. 2019).

Table 21: Electrolyzer sizes and CAPEX adapted to hourly excess wind power productions available for electrolysis**.** Wind power is the most significant source of electricity. Solar PV plays a marginal role in scenario 2 on Åland and there is no existing data for the hourly solar production on Åland. Therefore only the excess wind during the years 2031-2033 is analyzed for this table**.** These years were chosen since the 100 MW of new offshore wind power capacity were planned for 2030. The amount of hours with positive energy balance during one year are 3957 from the analyzed years 2031-2033. Additional costs of electricity import occur in the 2 MW case and costs for importing gaseous H_2 in the no electrolyzer case.

MWh/hour excess wind power production peak	150	100	50	20	10	5	2	no electrolyzer
Peak hourly H_2 production [Nm^3H_2/h][40]	28846	19231	9615	3846	1923	962	385	-
Peak hourly H_2 production [kg][41]	2595	1730	865	346	173	86	35	-
Needed electrolyzer capacity [MW]	144	96	48	19	10	5	2	-
Total CAPEX [M€][42]	144	96	48	19	10	5	2	-
OPEX [M€/year][43]	2,88	1,92	0,96	0,38	0,20	0,10	0,04	-
Energy for electrolysis [GWh][44]	239	221	146	70	38	19	7,9	-
Potential annual usable produced H_2 [1000 tonnes][45]	4,14	3,81	2,53	1,21	0,65	0,34	0,14	-
Annual water consumption [l]	51 800	47 800	31 700	15 200	8 100	4 200	1 700	-
Value of the annual produced H_2 [M€][46]	16,56	15,28	10,13	4,85	2,59	1,34	0,544	-
								-
Annual remaining electricity for export [GWh][47]	0,033	16,7	83,6	152	182	198	208	239

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40 Assumed average kWh/Nm3H2 production from the values in Table 19

41 $m = \frac{MpV}{Rt} = \frac{2*0,001008\frac{kg}{mol}101325Pa*V}{8,31415\frac{J}{molK}*273,15K}$

42 Assumed average CAPEX 1000 €/kW from the values in Table 19

43 Assumed average of OPEX 2 % of CAPEX in Table 19

44 Average from the years 2031-2033

45 Conversion factor 5,2 kWh/Nm^3H_2. -20% losses from compression, storage, transportation and fueling. $m = V_{H2} * p * R * T * M_{H2} = V_{H2} * 101325\ Pa * 8,31451\ J/molK * 273,15K * 2 * 0,001008\ kg/mol$

46 Assumed the value of H_2 to be low, 5 €/kg

47 Average from the years 2031-2033

Potential revenues from remaining exported electricity [M€][48]	0,001	0,666	3,34	6,09	7,27	7,92	8,33	8,62
Total revenues (H_2 + elec) [M€/year]	16,56	15,95	13,48	10,94	9,86	9,26	8,88	8,62
Cost of import [M€][49]							~9	

Looking at the total revenues from the cases with electrolyzers of different sizes, the annual revenues are higher for each alternative when comparing only to the export of electricity. However, simply the annual revenues won't give the whole truth. Especially the OPEX and high CAPEX for electrolyzer systems need to be taken in consideration. The NPV (Net Present Value) of the system is compared in the following section 0 below. With a reducing price of gaseous H_2, it would be reasonable to use the H_2 locally. If the prices of gaseous H_2 would increase, exporting would become more profitable.

4.2.3.3 Compression

The compressor needs to be capable of compressing the same amount of H_2 as the electrolyzer produces each hour, which is ~400 Nm^3H_2/h for scenario 1 (2 MW electrolyzer) and ~400 – 29 000 Nm^3H_2/h in scenario 2 (2 – 144 MW electrolyzer). Table 22 compares some properties between four different compressor suppliers.

Table 22: Comparison of compressor system properties between four different compressor suppliers. Sources in alphabetical order but in the table randomized order. (HyET. 2019) (Lia, G. 2019) (N.N. German compressor supplier. 2019) (N.N. Dutch compressor supplier. 2019)

Compressors	Comp. Supplier 1[50]	Comp. Supplier 2[51]	Comp. Supplier 3[52]	Comp. Supplier 4[53]
Pressure [bar]	10-30 → 700	30 → 700	3-15 → 500-875	20 → 700
Daily production capacity [kg/day]	480	863	120	863
CAPEX[54] **[€/kgH_2/day]**	2083	500	1000 – 2000	350 – 375
OPEX [€/kgH_2][55]	<1,0			
Energy use [kWh/kgH_2]	3,3	4,0	4,0	2,3

[48] The SPOT prices in NordPool vary 0,01-0,06 €/kWh (Nord Pool. 2019). 0,04 €/kWh was used in this table. Assumed transmission losses 10 % (Mörn J. 2019)
[49] Total average import / year for the electricity (demand + ferry variable 115 – 140 GWh / year). 0,80 kr/kWh (~0,08 €/kWh) is the price for electricity from Sweden (Mörn J. 2019).
[50] 140 kW, production capacity 20 kgH_2/h (10 bar input), 20 ft container, 1 M€ (N.N. Dutch compressor supplier. 2019)
[51] 100 kW, production capacity 36 kgH_2/h (30 bar input), 400 000 € (Lia G. 2019)
[52] 85 kW, production capacity 5 kgH_2/h (15 bar input), 240 000 € (HyET. 2019)
[53] 82 kW, production capacity 36 kgH_2/h (20 bar input), 285 700 € (N.N. German compressor supplier. 2019)
[54] Installation costs, control panel, container and loop cooling system included
[55] Assumed average between the different suppliers

To meet the demand of one single 1200 kW ferry, the minimum amount of hourly output from the electrolyzer needs to be 340 Nm^3H_2/h. Therefore we would need at least two of the above described compressors from supplier 1, two from supplier 2 and 4 and six from supplier 3. The number of compressors and their flow rate correlate to the hourly H_2 production of the electrolyzer. Compressors are a modular technology and can therefore be scaled up to the desired capacity by increasing the number of stacks.

There are always at least two compressors needed, one as backup, since compressors are the items that fail most often in the H_2 supply chain (Olsen, O.M. 2019).

4.2.4 Financials of the production scenarios

In order to get an overall view of the business case for both scenarios 1 and 2, the whole production chain from electrolysis to storage needs to be taken into consideration. The local power production costs are assumed to be zero due to uncertainties in the costs of the variable renewable energy architecture. CAPEX and OPEX of compression and storage are included since they also contribute to losses and are crucial for the whole system. Ground works, labor and installation costs are not included in this analysis.

Exporting gaseous H_2 could imply different outsourced alternatives for the use of H_2, which would also affect the price of it. For electricity companies, H_2 would not be able to compete against cheaper natural gas and electricity prices around 4 cents/kWh. However, if sold to biomass plants, refineries or carbon intensive industry, H_2 would be able to contribute in further refining into e.g. biofuels (Marcoux, M. 2019). At the moment it is not yet possible to quantify the extent of potential production of CH_4, which would need to be investigated further if building the biomass plant.

Biomass plants waste 60 % of their carbon in the process of producing biofuels. By combining gaseous H_2 into the process, the remaining unused carbon could also be used for producing more biofuel and improving the business case of biomass plants. Carbon capture from air is more expensive than biomass carbon. Biomass advanced biofuels have a demand also in refineries, who have to reduce their carbon intensity by 6 % between 2010 and 2020 (European Commission. 2019). If these refineries don't manage specific limits for CO_2 emissions, the fine is 470 €/ton CO_2 savings not achieved (ICCT. 2018). Heavy industries are also being directed towards decarbonization by 2050, which is not possible without expensive carbon capture or totally changing the production processes. Both alternatives require very large investments. These industries could have a potential interest in H_2 to make their production greener and stay within the emission quotas and targets. (Marcoux, M. 2019)

For the whole chain of electrolysis, compression, storage, transportation and fueling on Åland, at least one full time employee is needed in the maintenance of equipment and transportation of the gaseous H_2 to where it is needed. These new labor costs and costs of water for electrolysis are not taken into consideration in this analysis.

4.2.4.1 Financials of the H_2 production and storage – Scenario 1

The data from Table 20 is used as base for building up the financial view of scenario 1. The CAPEX and OPEX of compression and storage are also included. In the financial analysis in Table 23 and Figure 20, a case with a 5 MW and 10 MW electrolyzer running continuously was added for comparison.

Table 23: Summary of the expenses, revenues and NPV of the electrolysis with continuous operation of a 2 MW electrolyzer based on the information in Table 18, Table 19 and Table 20.

Continuous electrolyzer operation	2 MW	5 MW	10 MW
CAPEX electrolyzer [M€]	2	5	10
CAPEX compressors[56] [M€]	1,29	3,24	6,48
CAPEX storage[57] [€]	10,5	26,3	52,5
Total CAPEX [M€]	13,8	34,5	69,0
OPEX electrolyzer [M€/year]	0,040	0,10	0,2
OPEX compressors[58] [M€/year]	0,315	0,788	1,58
OPEX storage[59] [M€/year]	0,0525	0,131	0,262
Total OPEX [M€/year]	0,408	1,02	2,04
Total revenues (H_2 + elec) [€/year]	4,46	5,87	8,36
Electricity import for electrolyzer in continuous operation[60] [M€/year]	0,878	2,25	4,67
Annual Cash flow[61] [M€]	3,17	3,70	1,65
NPV (10 years, 7%[62] interest rate) [M€]	8,50	-16,3	-57,4
NPV without storage (10 years, 7% interest rate) [M€]	19,4	10,9	-3,07
NPV (20 years, 7% interest rate) [M€]	19,8	-7,00	-51,6
NPV without storage (20 years, 7% interest rate) [M€]	30,9	20,7	3,75

With continuous operation of the 2 MW electrolyzer throughout the year, the operation and maintenance costs of compression and storage and CAPEX of storage are in the same range as when running a 5 MW electrolyzer only specific times of the year with the production scenario 2. The reason behind this is that the amount of annually produced gaseous H_2 is similar in these both cases. However, if running a 5 MW electrolyzer continuously with electricity import when there is no own electricity production available, the annual cash flow is almost the same, slightly higher, even if the value of gaseous H_2 is low, 5 €/kg. In this case with the continuously running 5 MW electrolyzer the NPV would turn positive after 12 years, whereas the same happens after 5 years in the 2 MW electrolyzer case. However, the annual increase in NPV is higher for a larger electrolyzer but with a 10 MW electrolyzer running continuously, the CAPEX and OPEX increase enough to make production of H_2 with the price of 5 €/kg unprofitable.

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[56] Assumed CAPEX 1500 €/kgH_2/day (HyET. 2019) (N.N. Dutch compressor supplier. 2019) when the daily production capacity is below 5000 kgH_2/day and 1200 €/kgH_2/day with compression capacities above 5000 kgH_2/day.

[57] Assume storage capacity for about one month of H_2 production (1/12th of the year) with costs of 400 €/kgH_2, which is smaller than the assumed average of 600 €/kgH_2 for ferry fuel storage since the price would be smaller on this large scale.

[58] Assumed OPEX 1,0 €/kgH_2 (HyET. 2019)

[59] 2 €/kgH_2 capacity / year) (Fredheim V. 2019) (Olsen O.M. 2019)

[60] Only to keep the electrolyzer in continuous operation. Does not include the annual electricity gaps.

[61] Total annual revenues minus OPEX minus costs of imported electricity (80 €/MWh) to keep the electrolyzer running continuously

[62] The interest rate for wind power projects are usually 4-8% (Suomen Tuulivoimayhdistys. 2019). Here 7% was used.

With a higher value of the produced H_2 and, lower CAPEX of storage and lower OPEX of compression, it would financially be profitable to have a slightly bigger electrolyzer running continuously. Since larger electrolyzers result in high storage CAPEX, pipelines could be suitable for larger scale H_2 usage and save in storage expenses.

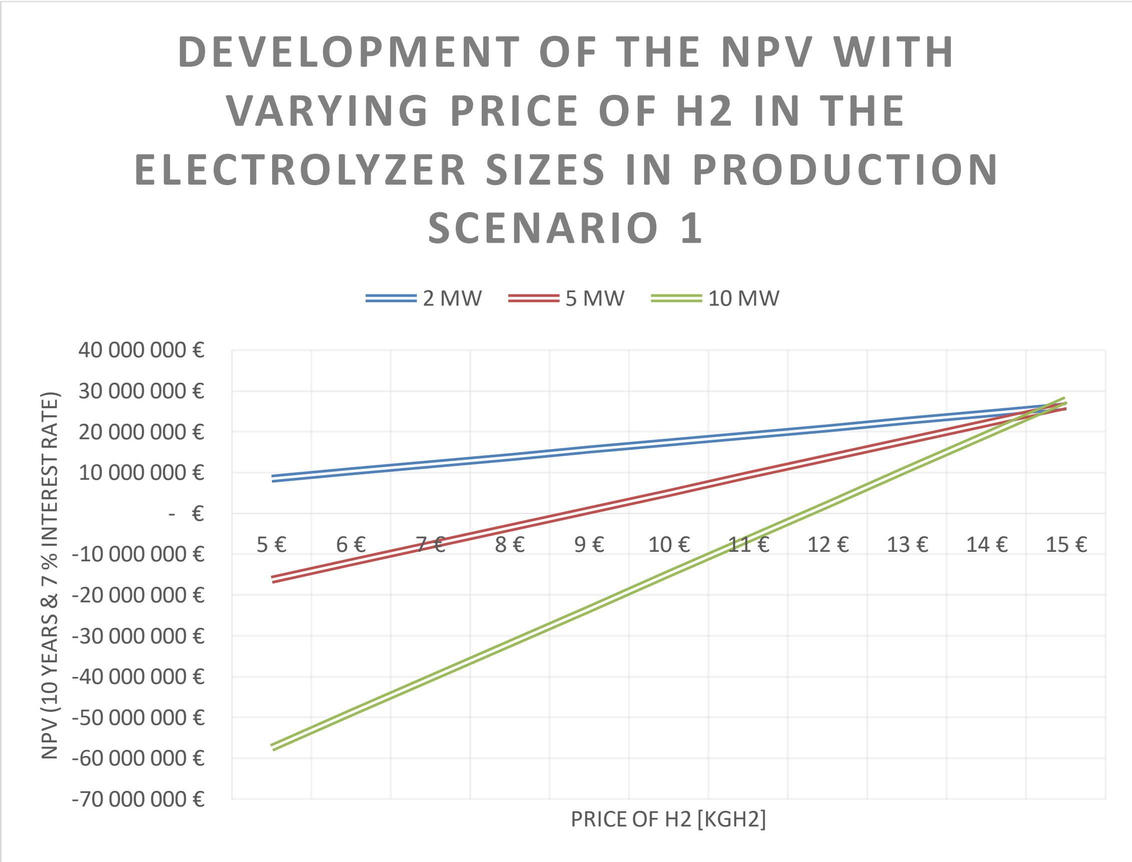

Figure 20: Development of the NPV (10 years period and 7 % interest rate) with increased prices of gaseous H2 for export in scenario 1 and their corresponding electrolyzer capacity of 2 MW and added 5 MW electrolyzer for the financial comparison.

The NPV takes into consideration the import demand of electricity for running the electrolyzer continuously. With a larger continuously running electrolyzer, the NPV value reacts more to price changes of H_2. The steeper line of the 5 MW and 10 MW electrolyzer compared to the 2 MW electrolyzer proves this. With a higher value of H_2 than 15 €/kg, the a larger electrolyzer, >10 MW, would be profitable.

4.2.4.2 Financials of the H_2 production and storage – Scenario 2

To get a total financial look of the business case for the large scale gaseous H_2 production in scenario 2, we could assume the same five cases as in Table 21 above but add compression and storage components for the whole system.

Table 24: Summary of the expenses, revenues and NPV in the cases with different electrolyzer sizes and corresponding compressors and storage based on the data presented in Table 18, Table 19 and Table 20 for scenario 2. Operation and maintenance costs of the cable and potential new cable costs if more capacity is transferred are excluded.

MWh excess wind power production peak	150	100	50	20	10	5	2[63]	no elec-tro-lyzer[64]
Needed electro-lyzer capacity [MW]	144	96	48	19	10	5	2	-
CAPEX electro-lyzer [M€]	144	96	48	19	10	5	2	-
CAPEX compres-sors[65] [M€]	74,7	49,8	24,9	9,96	6,23	3,11	1,25	-
CAPEX storage[66] [€]	124	115	56	36	19	10	4	-
Total CAPEX [M€]	343	260	149	65,3	35,6	18,1	7,33	-
OPEX electro-lyzer [M€/year]	2,88	1,92	0,96	0,38	0,20	0,10	0,04	-
OPEX compres-sors[67] [M€/year]	4,14	3,82	2,43	1,21	0,647	0,335	0,136	-
OPEX storage[68] [M€/year]	0,621	0,572	0,380	0,182	0,097	0,050	0,020	-
Total OPEX [M€/year]	7,64	6,31	3,87	1,77	0,943	0,484	0,176	-
Total revenues (H_2 + elec) [€/year]	16,56	15,95	13,48	10,94	9,86	9,26	8,88	8,62
NPV (10 years, 7%[69] interest rate) [M€]	-280	-193	-81,4	-0,931	27,0	43,5	47,5	45,5
NPV without storage (10 years, 7% interest rate) [M€]	-152	-34,1	-2,79	36,7	47,1	53,9	51,7	-

63 Electricity import costs of ~880 000 €/year are included in order to keep the H_2 ferry running.
64 Includes H_2 annual import costs of 2 135 250 €/year with an assumed price of 8 €/kgH_2 to meet the demand of ~267 000 kg of the H_2 ferry.
65 Assumed CAPEX 1500 €/kgH_2/day (HyET. 2019) (N.N. Dutch compressor supplier. 2019) when the daily production capacity is below 5000 kgH_2/day and 1200 €/kgH_2/day with compression capacities above 5000 kgH_2/day.
66 Assume storage capacity for about one month of H_2 production (1/12th of the year) with costs of 400 €/kgH_2, which is smaller than the assumed average of 600 €/kgH_2 for ferry fuel storage since the price would be smaller on this large scale.
67 Assumed OPEX 1,0 €/kgH_2 (HyET. 2019)
68 2 €/kgH_2 capacity / year) (Fredheim, V. 2019) (Olsen, O.M. 2019)
69 The interest rate for wind power projects are usually 4-8% (Suomen Tuulivoimayhdistys. 2019). Here 7% was used.

NPV (20 years, 7% interest rate) [M€]	-248	-158	-47,1	31,8	58,8	74,8	75,3	68,7
NPV without storage (20 years, 7% interest rate) [M€]	-118	-37,7	32,9	70,1	79,2	85,4	79,6	-

Having electrolyzers of the size 100 or 144 MW results in an extremely negative NPV, which still after 20 years has a negative value of 100-200 M€. A large electrolyzer also requires huge capacities of compression and storage, which have high CAPEX and OPEX. With a smaller electrolyzer, the number of full load hours of the electrolysis increases, system CAPEX and OPEX decreases and the NPV turns positive. A 20 MW electrolyzer turns the NPV positive after 12 years, and 10 MW electrolyzer after 5 years. A ~20 MW electrolyzer could come in question, especially with a higher value of H_2, as proposed in Figure 21.

It is to be noted that the no electrolyzer case does not include maintenance costs and potential costs of a new cable, which would need more research if higher capacities are transferred through the cables. With financial support on the investment costs in H_2 production and finding the client, e.g. biomass plants or biofuel producer, who could get a high benefit from the H_2 and thereby value it the most would improve the NPV.

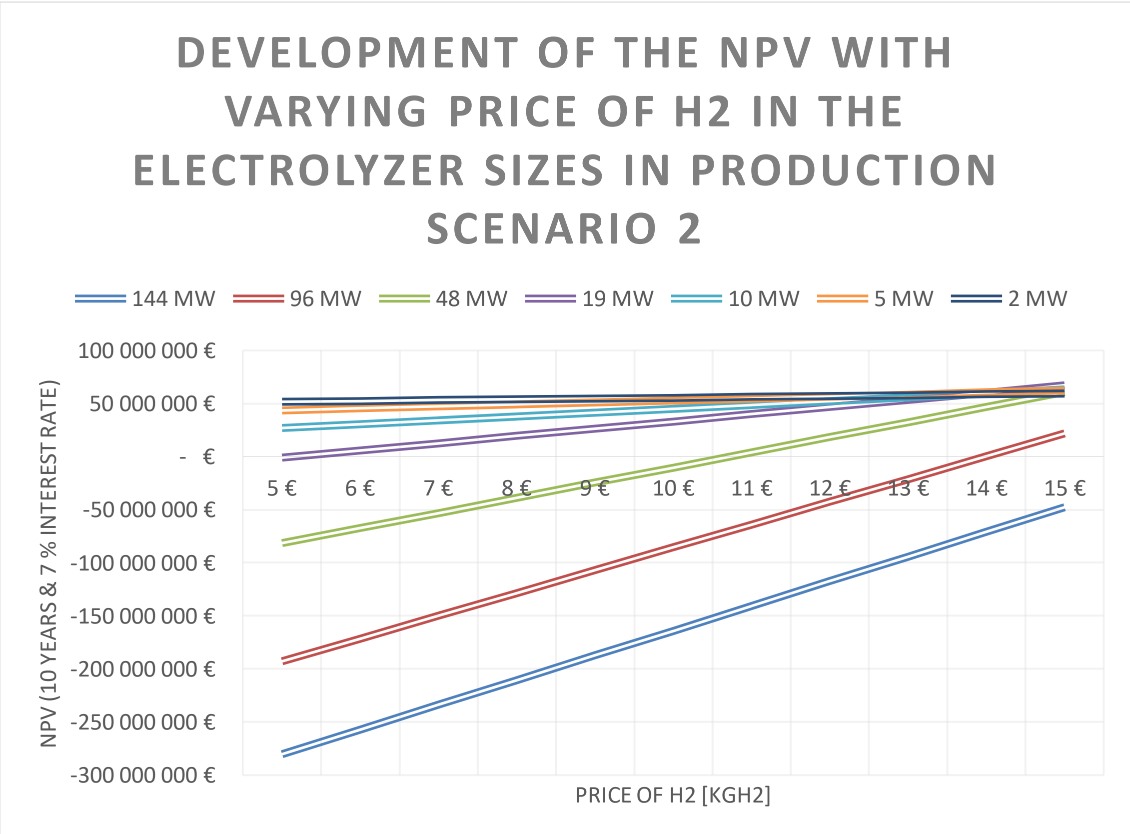

Figure 21: Development of the NPV (10 years period and 7 % interest rate) with increased prices of gaseous H_2 for export in scenario 2 and their corresponding electrolysis capacities.

Finding the application, where H_2 would have the highest value, and target customer, who would be willing to pay more for the H_2, would improve the business case, as visualized through the variation in the NPV in Figure 20 and Figure 21, of exporting H_2. A potential path could be selling the excess produced H_2 to biomass plants, who then produce biofuels and create a higher value product. Export and transport of gaseous H_2 is more expensive than for H_2 enhanced biofuels, however, producing these biofuels is more expensive than producing gaseous H_2. Therefore finding local usage for H_2 seems financially promising for Åland. (Marcoux, M. 2019)

The higher the production volume, the steeper the NPV development curve. In scenario 1 we have a much smaller production capacity and thereby also a lower NPV. However, scenario 1 still indicates a positive NPV at all prices of H_2 above 5 €/kgH_2. In scenario 2 we have several electrolyzer sizes according to the amount of electricity they could convert to H_2 each hour as in Table 21. A higher price of gaseous H_2 would significantly improve the business case from the analysis in Table 23 and Table 24. On a longer time period than 10 years, the NPV would additionally rise to higher positive values.

4.2.5 **Fueling**

There are three breaks of ~1 hour in the ferry schedule, where one potential fueling could happen.

1. Once per day fueling (tank size ~600 kg)
    a. Fueling in 1 hour: Flowrate 10 kg/min
    b. Fueling in 30 min: Flowrate 20 kg/min
2. Twice per day fueling (tank size ~300 kg)
    a. Fueling in 1 hour: Flowrate: 5 kg/min
    b. Fueling in 30 min: Flowrate 10 kg/min

Higher fueling rates require more cooling since the industry standard on tanks is today 85 °C (Pratt, J.W. & Chan, S.H. 2017). Fueling with a higher flowrate than ~7 kg/min, which is the current fueling protocol limit, would require an additional cooler in the fueling (Braatz, C. 2019). The higher the pressure, the higher also the cooling demand.

Using cascade filling, high pressure gas cylinder storage used to refill smaller compressed cylinders, it is possible to fill fast and without using the compressor and the compressor can refill the used cylinders while the ferry is in operation. With cascade filling the compressor can have a lower capacity and lower costs. (Olsen, O.M. 2019)

Since the fuel demand is very high, changeable tanks would require cranes in the fueling phase. Therefore, refueling on the spot is the predominant fueling method. (Vänskä, K. 2019)

A fueling station using storage tanks of Type III or IV and a flowrate of 10 kg/min, would cost around 10 – 15 M€ (Braatz, C. 2019). Fueling is not looked into further in this study.

4.3 H_2 value chain for ferry operations

To meet the H_2 fuel demand of the ferry, we would in Scenario 1 need a 2 MW electrolyzer running continuously and in Scenario 2 a 5 MW electrolyzer running when excess electricity is available. Table 25 below summarizes the costs of the fuel cell production system and fuel cell ferry operation and presents the production of gaseous H_2 and the demand of the ferry.

Table 25: Summary of the investment and operational costs of the fuel cell production system and fuel cells for ferry operation. A fueling station will result in additional installation costs of 10-15 M€.

H_2 production chain	**CAPEX [€]**	**OPEX [€]**	**Annual produced H_2 [kg]**
Scenario 1 (2MW electrolyzer with continuous operation)	13 800 000	408 000	315 000
Scenario 2 (5MW electrolyzer run with excess power)	18 100 000	484 000	340 000
Fuel cell ferry system (Svinö – Föglö route)	**CAPEX [€]**	**OPEX [€]**	**Annual H_2 demand [kg]**
On-board fuel cell system (1200 kW incl. storage)	2 315 500	43 200	267 000

If we manage to internalize the environmental costs generated by the diesel operators (see estimate in Table 15), hydrogen for ferry operations seems economically feasible as an alternative to diesel. It is an opportunity for the government to set an example for the future to reduce CO_2 emissions in the present global warming debate.

At present, the variable renewable architecture, including its content of biomass, it's ownership, size of the electrolyzer and its other uses and the ownership of the hydrogen architecture are all unclear, wherefore stating the costs of locally produced H_2 is not possible. A follow-up feasibility study, policy and economic analysis, of the Åland total system for the ferry would be necessary.

5 Conclusions

The inclusion of H_2 in the energy system of the Åland islands is being studied for balancing the local variable renewable energy production. New wind capacity of 70 – 170 MW will be built. This work focuses on producing gaseous H_2 locally from excess electricity and using it as fuel for a ferry. Two main production scenarios, scenario 1, Biomass base-load scenario, and scenario 2, High-wind scenario, were used with a focus on the wind and biomass production. Corresponding electrolyzer capacities were investigated for both scenarios. For producing gaseous H_2 locally, the main components in the system are an electrolyzer, a compressor, storage and fueling. Business cases for all scenarios were built up with NPV for comparison.

Three different types of electrolyzers, AEC, PEMEC and SOEC, were investigated and PEMEC chosen to be the most potential alternative due to its dynamic power range, power density, efficiency, promising technology and price development. However, AEC is the most mature technology and there is still little evidence of the promising SOEC. The production of gaseous H_2, electrolysis, requires, despite electricity, also water. The water has to be clean tap water but the option of using seawater, with e.g. reverse osmosis, would need to be investigated further due to the fact that Åland is surrounded by seawater.

The electrolysis sector must develop globally to a gigawatt industry to meet the demand of emission reductions. This requires greater demand and an annual increase in volume of several MW in different industries in order to create a robust and smooth supply chain (Smolinka, T. et al. 2018).

One large electrolysis central with compression of the gaseous H_2 to 500 or 700 bar is financially the most suitable at the time being for a place with the size and population of Åland. Compression will happen alongside the electrolysis and the produced H_2 would be stored in composite cylinders, which are then easy to transport to the ferry. If there are plans for developing the H_2 usage broader on Åland, it would make sense to have a central electrolyzer where the potential future demand is the largest. However, if H_2 is only produced for one ferry, the electrolysis system should be positioned by the harbor in combination with the fueling station.

Compression from the outlet pressure of 20 – 30 bar from the electrolyzer up to ~500 bar is required to reduce the volume of the gaseous H_2 and thereby make transportation and fueling easier. The system always needs at least two compressors, one as back-up, since the compressor is the component in the H_2 chain with highest risk of failure. When scaling up the electrolyzer, similarly compression needs to be scaled up. The total CAPEX and OPEX of the whole system become extremely high, as seen in Table 23, and the profitability reduces when the electrolyzer load is lower.

The gaseous H_2 would be stored in high pressure (300 – 500 bar) cylinder tanks easy to transport by trucks to the harbor and transfer to the ferry or potentially export overseas. If the electrolysis and compression is in the harbor, no truck transport is needed. The number and positioning of electrolyzers depends on the scale of local H_2 production and usage. With larger volumes and broader use of locally produced H_2, the alternative of distribution through pipelines could become potential.

The fueling would work by swapping out the pressurized tanks onto the ferry. Alternatively, a similar fueling as for fuel cell vehicles, but on a much larger scale, by simply filling the on-board tank could be implemented.

The most promising fuel cell technology for marine use is currently PEMFC due to its high power density, relatively good efficiency and operating temperature, low O&M costs and reducing cost projections.

When comparing fuel cell ferries and diesel engines ferries, the costs distributed on the lifetime of the system become lower for fuel cells in the long run even if the CAPEX for fuel cells are double the one of diesel engines. The main reason behind this is the social cost caused by emissions from diesel engines and lower maintenance costs of fuel cells. In this case we don't look at profits, only on costs when using the NPV methodology for comparing the profitability. Social costs represent costs the investor socializes, e.g. the individual consumer has to bear. Including social costs the annualized costs for fuel cell ferries become ~13% less or NPV ~32% higher compared to conventional ferries. However, without social costs the NPV becomes >100% lower for fuel cell ferries than conventional ones. These differences are substantial. In order to make the NPV of diesel engines and fuel cells on the same level, the CAPEX costs of fuel cells would have to be 60-70% smaller.

Diesel engines have been around for over 100 years, whereas fuel cells are an emerging technology. There is therefore a likely price reduction for fuel cells, improving their relative costs. This fact opens an important role for the state acting as a lead investor and operator of this future bound technology.

Figure 22 below visualizes some advantages brought by fuel cell ferries and potential further development of the H_2 industry on Åland and challenges to tackle before being able to profit from all the advantages of fuel cell ferries.

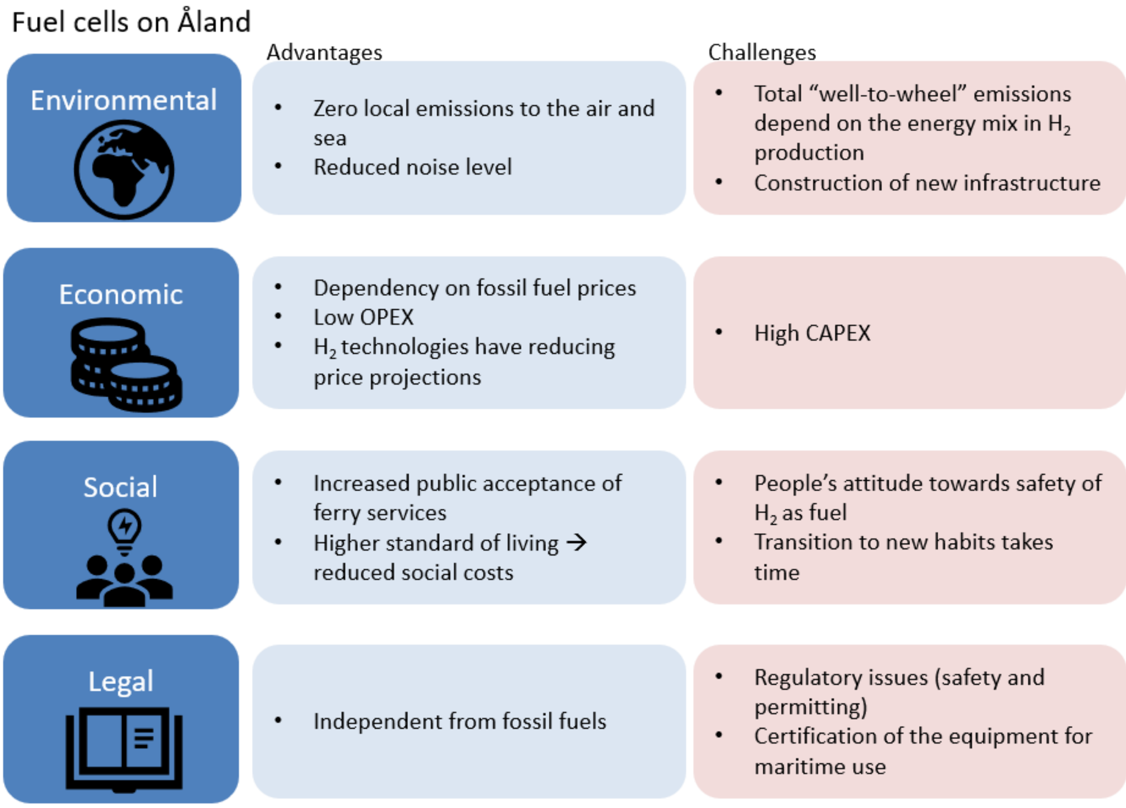

Figure 22: Advantages and challenges of the deployment of H_2 driven fuel cell ferries on Åland.

The CAPEX for gaseous H_2 production are large for the whole system. Especially when the H_2 production is adapted to high hourly flows with 144 or 96 MW electrolyzers, all components have to be suited for high hourly productions, and even after 20 years, the NPV won't become positive. However, in Scenario 2, a 20 MW electrolyzer, run when excess electricity is available with a corresponding compressor and storage, would result in a positive NPV after 12 years. The NPV could be increased if the electrolyzer was run continuously. The cases with a 5 MW, 10 MW or 20 MW electrolyzer show a great potential in the NPV value comparison.

5.1 Next Steps

Looking into a scenario with a continuously running electrolyzer, which is bigger than in scenario 1, a potential midway scenario between the production scenarios 1 and 2 would still need to be investigated. A deeper understanding of the fueling alternatives would also require more research for an overall look of the H_2 production chain for fueling ferries.

It is to be noted that these calculations include several rough assumptions based on information from electrolyzer, compressor, storage and fuel cell manufacturers, experts within the field and literature causing uncertainty. Concerning social costs there has to be a political dialogue, communication with different stakeholders, the government, press and the public and an agreement for consistency.

With a higher value of the produced H_2 and, lower CAPEX of storage and lower OPEX of compression, it would financially be profitable to have a slightly bigger electrolyzer running continuously. Finding the right customer, who most needs the gaseous H_2 could result in a significantly better business case with higher revenues per kg of the exported H_2. The higher the production volumes of gaseous H_2, the greater the positive influence a price increase could have on the business case and NPV. Analysis on the fluctuating electricity price is still required to optimize the size of the electolyzer and with what electricity price it would be most favorable to produce local H_2 and for what price.

To favor local use of H_2, the prices of H_2 should be kept low. However, with more H_2 production than needed for the ferry, export prices should be higher to improve the business case. Policy should close the price gap to make fuel cell ferries and local gaseous H_2 profitable. More research within policy is needed. Environmental and social reasons and costs support the development of a H_2 industry on Åland.

For a broader extent of the use of H_2, heat would need to be included in the analysis due to Nordic weather conditions with a high heating demand. SOFC could be suitable since they can be ran similarly to a CHP plant. However, SOFC are not yet commercialized on larger scale and reach the highest efficiencies when running on CH_4. Following the development of new technologies and assessing potential technologies for a macroeconomic view of the system is necessary.

It is still to be discussed who exactly would be the owner of this local H2 production or if it would be divided into parts in the production chain. Follow-up work with Landskapsregeringen, Allwinds and Flexens is prerequisite for continuation of the hydrogen architecture and make more concret the costs for different stakeholders of the hydrogen system and production estimation on daily and seasonal perspective. What would be the role of Ålands Landskapsregering or Allwinds, who produces the excess wind power, or would that perhaps be the task for a new company?

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Annex 1

Table 26: Monthly remaining/overflow energy with the production in scenario 1 and subtracted demand

Total residual	January	February	March	April	May	June	July	August	September	October	November	December	Sum (GWh)
		Scenario 1											
2019	-32,49458669	-29,9729676	-25,889	-21,508642	-16,1112	-12,66266	-13,04	-14,278002	-19,205012	-23,2380654	-25,0814086	-31,24712832	-264,72709
2020	-22,70352052	-21,80030331	-11,2195	-12,723975	-10,9551	-4,512817	-9,088	-7,0276109	-13,609791	-12,501544	-16,7954261	-18,18650088	-161,12455
2021	-20,53196835	-24,96600059	-15,3197	-13,498704	-6,98011	-2,216331	-9,885	-1,7552061	-1,449454	-5,50075388	-18,9228455	-22,64203694	-143,66803
2022	-3,752402059	-4,024869881	-4,11946	-3,1130568	-1,89108	2,361435	1,012	4,33545742	-3,4670668	5,47838174	6,05643342	0,5934564	-0,5306911
2023	-5,226032979	-5,925840083	7,457217	-1,6323302	-2,61793	4,799898	-0,927	1,97064526	-3,8920002	5,98479823	0,3500054	0,310891577	0,652023
2024	-7,162603405	-12,63069189	-1,17601	-5,748734	-0,79619	4,14792	-3,528	4,10795133	5,96344973	8,77297233	-5,731893	-9,382021997	-23,164232
2025	-1,333589049	-1,94066972	-3,38971	-1,3902179	-0,58449	3,995524	2,378	6,95150061	-2,2345471	8,10168765	9,49883496	3,903311102	23,9554651
2026	-3,008870081	-4,136514231	10,57211	0,44870474	-1,41018	6,960462	0,089	4,16026406	-2,6944455	8,77919449	2,72868473	3,657309385	26,1460834
2027	-5,23828238	-12,09573687	0,283098	-4,4279983	0,823144	6,217451	-2,993	6,77226745	9,19147584	12,1958576	-4,49086652	-7,879714691	-1,641882
2028	-3,254152984	-3,70118666	-4,83013	-2,6705938	-1,54478	3,195289	1,578	5,99121864	-3,3548761	6,6612647	7,89836501	1,982747167	7,95076569
2029	-4,958242475	-5,923438925	9,110084	-0,8508769	-2,38486	6,148224	-0,723	3,18557787	-3,8273068	7,3171652	1,10420773	1,707936991	9,90558609
2030	-7,21689536	-13,90946544	-1,20086	-5,7470737	-0,16616	5,393029	-3,817	5,78296096	8,03728494	10,7118978	-6,13971067	-9,858327671	-18,130324
2031	-5,262445159	-5,542121154	-6,33635	-4,0094553	-2,54892	2,358501	0,741	4,98707255	-4,5263799	5,15504557	6,2247882	-0,025545007	-8,7850024
2032	-6,996659032	-7,791987436	7,581272	-2,2098212	-3,40407	5,298883	-1,572	2,16636959	-5,0163831	5,78835278	-0,59447273	-0,330479566	-7,0812186
2033	-9,285888166	-15,80604217	-2,75261	-7,1264022	-1,20066	4,530949	-4,679	4,74846456	6,83037247	9,16015324	-7,86387134	-11,92732048	-35,37193
2034	-7,362472856	-7,467146543	-7,91137	-5,4094738	-3,59894	1,483489	-0,134	3,93705871	-5,751396	3,5800248	4,47476512	-2,125572705	-26,285233
2035	-9,128187145	-9,745888206	5,982626	-3,63084	-4,46984	4,410747	-2,46	1,10060553	-6,2597745	4,1897067	-2,37074616	-2,462007679	-24,843953
2036	-11,4493892	-17,78925146	-4,37523	-8,5687362	-2,28241	3,62949	-5,581	3,66671404	5,5683302	7,53752746	-9,66678887	-14,09082151	-53,401106
2037	-9,558426407	-9,480103964	-9,55834	-6,8734428	-4,69691	0,568509	-1,049	2,83908193	-7,0323689	1,93305963	2,64480383	-4,321526255	-44,584846
2038	-11,35708	-11,78903999	4,310956	-5,1167685	-5,58428	3,482041	-3,389	-0,0138409	-7,559962	2,51803706	-4,22815687	-4,690900532	-43,41806
2039	-13,71171545	-19,86305051	-6,07198	-10,076954	-3,41357	2,686854	-6,523	2,53555091	4,24863989	5,84078278	-11,5520607	-16,35314776	-72,253824
2040	-11,85468755	-11,58501001	-11,2805	-8,4042836	-5,84504	-0,388267	-2,006	1,69095136	-8,3718546	0,21086378	0,73125288	-6,617787395	-63,720356

Table 27: Months with positive energy balance with the production in scenario 1 and subtracted demand

Total residual	Scenario 1												
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Sum (GWh)**
2019	-	-	-	-	-	-	-	-	-	-	-	-	0
2020	-	-	-	-	-	-	-	-	-	-	-	-	0
2021	-	-	-	-	-	-	-	-	-	-	-	-	0
2022	-	-	-	-	-	2,361435	1,012	4,33545742	-	5,47838174	6,05643342	0,5934564	19,8372433
2023	-	-	7,457217	-	-	4,799898	-	1,97064526	-	5,98479823	0,3500054	0,310891577	20,8734562
2024	-	-	-	-	-	4,14792	-	4,10795133	5,96344973	8,77297233	-	-	22,9922932
2025	-	-	-	-	-	3,995524	2,378	6,95150061	-	8,10168765	9,49883496	3,903311102	34,8286904
2026	-	-	10,57211	0,44870474	-	6,960462	0,089	4,16026406	-	8,77919449	2,72868473	3,657309385	37,396092
2027	-	-	0,283098	-	0,823144	6,217451	-	6,77226745	9,19147584	12,1958576	-	-	35,483295
2028	-	-	-	-	-	3,195289	1,578	5,99121864	-	6,6612647	7,89836501	1,982747167	27,3064816
2029	-	-	9,110084	-	-	6,148224	-	3,18557787	-	7,3171652	1,10420773	1,707936991	28,5731956
2030	-	-	-	-	-	5,393029	-	5,78296096	8,03728494	10,7118978	-	-	29,9251729
2031	-	-	-	-	-	2,358501	0,741	4,98707255	-	5,15504557	6,2247882	-	19,4662156
2032	-	-	7,581272	-	-	5,298883	-	2,16636959	-	5,78835278	-	-	20,8348775
2033	-	-	-	-	-	4,530949	-	4,74846456	6,83037247	9,16015324	-	-	25,2699391
2034	-	-	-	-	-	1,483489	-	3,93705871	-	3,5800248	4,47476512	-	13,4753381
2035	-	-	5,982626	-	-	4,410747	-	1,10060553	-	4,1897067	-	-	15,6836846
2036	-	-	-	-	-	3,62949	-	3,66671404	5,5683302	7,53752746	-	-	20,4020618
2037	-	-	-	-	-	0,568509	-	2,83908193	-	1,93305963	2,64480383	-	7,98545421
2038	-	-	4,310956	-	-	3,482041	-	-	-	2,51803706	-	-	10,3110344
2039	-	-	-	-	-	2,686854	-	2,53555091	4,24863989	5,84078278	-	-	15,3118277
2040	-	-	-	-	-	-	-	1,69095136	-	0,21086378	0,73125288	-	2,63306802

Table 28: Monthly remaining/overflow energy with the production in scenario 2 and subtracted demand

Total residual	January	February (Scenario 2)	March	April	May	June	July	August	September	October	November	December	Sum (GWh)
2019	-32,49458669	-29,9729676	-25,889	-21,508642	-16,1112	-12,66266	-13,04	-14,278002	-19,205012	-23,2380654	-25,0814086	-31,24712832	-264,72709
2020	-22,70352052	-21,80030331	-11,2195	-12,723975	-10,9551	-4,512817	-9,088	-7,0276109	-13,609791	-12,501544	-16,7954261	-18,18650088	-161,12455
2021	-20,53196835	-24,96600059	-15,3197	-13,498704	-6,98011	-2,216331	-9,885	-1,7552061	-1,449454	-5,50075388	-18,9228455	-22,64203694	-143,66803
2022	-18,53277206	-17,28018988	-18,1525	-10,047617	-6,14152	-1,665825	-3,231	-0,0219026	-10,244247	-9,15132826	-8,24393658	-14,2233636	-116,9363
2023	-20,00640298	-19,18116008	-6,57585	-8,5668902	-6,86837	0,772638	-5,17	-2,3867147	-10,66918	-8,64491177	-13,9503646	-14,50592842	-115,75359
2024	-21,94297341	-25,88601189	-15,2091	-12,683294	-5,04663	0,12066	-7,772	-0,2494087	-0,8137303	-5,85673767	-20,032263	-24,198842	-139,56984
2025	-16,11395905	-15,19598972	-17,4228	-8,3247779	-4,83493	-0,031736	-1,865	2,59414061	-9,0117271	-6,52802235	-4,80153504	-10,9135089	-92,450145
2026	-17,78924008	-17,39183423	-3,46096	-6,4858553	-5,66062	2,933202	-4,154	-0,1970959	-9,4716255	-5,85051551	-11,5716853	-11,15951061	-90,259527
2027	-20,01865238	-25,35105687	-13,75	-11,362558	-3,4273	2,190191	-7,236	2,41490745	2,41429584	-2,43385242	-18,7912365	-22,69653469	-118,04749
2028	-18,03452298	-16,95650666	-18,8632	-9,6051538	-5,79522	-0,831971	-2,666	1,63385864	-10,132056	-7,9684453	-6,40200499	-12,83407283	-108,45484
2029	-19,73861247	-19,17875893	-4,92299	-7,7854369	-6,6353	2,120964	-4,966	-1,1717821	-10,604487	-7,3125448	-13,1961623	-13,10888301	-106,50002
2030	3,446082915	-12,03508899	3,954344	4,5329651	12,68624	20,4187	0,768	25,4949791	30,1387615	28,3623289	-1,65445288	-2,045224185	114,067581
2031	8,327057764	6,321308369	-6,32106	8,70454607	8,033424	14,32703	10,7	24,1922269	4,05583525	17,1973813	25,0774725	19,46778586	140,087537
2032	5,432176601	2,273974591	23,63527	13,0145982	6,611224	20,85377	6,141	18,6205281	3,46835556	19,109041	11,3197858	19,59027214	150,069722
2033	1,377090109	-13,93166572	2,402599	3,15363657	11,65174	19,55662	-0,094	24,4604827	28,931849	26,8105843	-3,37861355	-4,11421699	96,8259745
2034	6,227030067	4,396282979	-7,89608	7,30452761	6,98341	13,45201	9,83	23,1422131	2,83081909	15,6223605	23,3274494	17,36775816	122,587306
2035	3,300648488	0,320073821	22,03662	11,5935795	5,54546	19,96563	5,253	17,554764	2,22496417	17,5103949	9,54351238	17,45874403	132,306988
2036	-0,786410926	-15,91487501	0,779974	1,71130254	10,56999	18,65517	-0,996	23,3787322	27,6698068	25,1879585	-5,18153108	-6,277718025	78,7967992
2037	4,031076517	2,383325558	-9,54304	5,84055857	5,885433	12,53703	8,915	22,0442363	1,54984619	13,9753954	21,4974881	15,17180461	104,287693
2038	1,071755634	-1,723077962	20,36495	10,1076509	4,431014	19,03692	4,324	16,4403176	0,92477667	15,8387252	7,68610167	15,22985117	113,732881
2039	-3,048737172	-17,98867406	-0,91677	0,20308505	9,438829	17,71253	-1,938	22,2475691	26,3501165	23,4912138	-7,06680295	-8,540044271	59,9440804
2040	1,734815377	0,278419513	-11,2652	4,30971781	4,737303	11,58026	7:,958	20,8961057	0,21036052	12,2531995	19,5839372	12,87554347	85,1521834

Table 29: Months with positive energy balance with the production in scenario 2 and subtracted demand

Total residual		Scenario 2											
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Sum (GWh)**
2019	-	-	-	-	-	-	-	-	-	-	-	-	0
2020	-	-	-	-	-	-	-	-	-	-	-	-	0
2021	-	-	-	-	-	-	-	-	-	-	-	-	0
2022	-	-	-	-	-	-	-	-	-	-	-	-	0
2023	-	-	-	-	-	0,772638	-	-	-	-	-	-	0,77263829
2024	-	-	-	-	-	0,12066	-	-	-	-	-	-	0,12065978
2025	-	-	-	-	-	-	-	2,59414061	-	-	-	-	2,59414061
2026	-	-	-	-	-	2,933202	-	-	-	-	-	-	2,93320207
2027	-	-	-	-	-	2,190191	-	2,41490745	2,41429584	-	-	-	7,01939457
2028	-	-	-	-	-	-	-	1,63385864	-	-	-	-	1,63385864
2029	-	-	-	-	-	2,120964	-	-	-	-	-	-	2,12096357
2030	3,446082915	-	3,954344	4,5329651	12,68624	20,4187	0,768	25,4949791	30,1387615	28,3623289	-	-	129,802347
2031	8,327057764	6,321308369	-	8,70454607	8,033424	14,32703	10,7	24,1922269	4,05583525	17,1973813	25,0774725	19,46778586	146,408593
2032	5,432176601	2,273974591	23,63527	13,0145982	6,611224	20,85377	6,141	18,6205281	3,46835556	19,109041	11,3197858	19,59027214	150,069722
2033	1,377090109	-	2,402599	3,15363657	11,65174	19,55662	-	24,4604827	28,931849	26,8105843	-	-	118,34461
2034	6,227030067	4,396282979	-	7,30452761	6,98341	13,45201	9,83	23,1422131	2,83081909	15,6223605	23,3274494	17,36775816	130,483383
2035	3,300648488	0,320073821	22,03662	11,5935795	5,54546	19,96563	5,253	17,554764	2,22496417	17,5103949	9,54351238	17,45874403	132,306988
2036	-	-	0,779974	1,71130254	10,56999	18,65517	-	23,3787322	27,6698068	25,1879585	-	-	107,952932
2037	4,031076517	2,383325558	-	5,84055857	5,885433	12,53703	8,915	22,0442363	1,54984619	13,9753954	21,4974881	15,17180461	113,830735
2038	1,071755634	-	20,36495	10,1076509	4,431014	19,03692	4,324	16,4403176	0,92477667	15,8387252	7,68610167	15,22985117	115,455959
2039	-	-	-	0,20308505	9,438829	17,71253	-	22,2475691	26,3501165	23,4912138	-	-	99,4433437
2040	1,734815377	0,278419513	-	4,30971781	4,737303	11,58026	7,958	20,8961057	0,21036052	12,2531995	19,5839372	12,87554347	96,4174216